IMPROVING GAS AND SAND SEPARATION IN LATERAL WELLS

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ABSTRACT

Gas and sand interference are two of the most common culprits that hinder production in lateral wells, which is why it is particularly important for operators to pursue as many gas and sand mitigation efforts as possible using innovative downhole tools.

The problem is twofold: Gas interference can lead to poor pump efficiency and severe sand issues can lead to sticking and excessive wear and tear on the pump. Both of which lead to unnecessary and costly operational expenses due to well failures and overall poor system efficiencies. Recognizing the ineffectiveness and shortcomings of current models of gas and sand separator systems on the market, WellWorx set out to design a more effective all-in-one system to combat the dual issues in rod pump wells.

In the first stage of the tool design, fluids enter the sand separator and solids are removed using a dual-channel spiral system that forces solids into a three-foot sand drain before entering into the mud anchor, maximizing the distance between pump intake and solids discharge. This three-foot sand drain is innovative in that it is the only tool on the market that moves sand discharge away from pump suction.

In the second stage of the design, the gas separator creates the greatest tool OD to casing ID ratio possible, allowing operators to maximize the separation area available in the annulus of the given well bore. By increasing the separation area available in the annulus, we decrease the downward fluid velocity of the fluid prior to pump entry, allowing gas to escape up the casing.

Installing this type of equipment reduces gas and sand interference, which in turn increases pump efficiency and extends the life of all downhole equipment. By staying in a higher production range for a longer period of time, operators are allowed more freedom in pumping practices with or without lowering the pump in the curve, all of which raise profitability.

This paper presents the technology behind this combination gas and sand separation system and offers case study results that prove the positive impact of this tool on overall operating expenses.

INTRODUCTION

Throughout recent years, rod pumping horizontal wells in the Permian Basin has proven to be extremely challenging. So much so that other forms of artificial lift are often considered as alternatives due to the difficulties associated with new wellbores. Some of these major difficulties with rod pumping include gas interference issues leading to poor pump efficiency, increased gas pounding leading to more rod and pump failures, and inefficient drawdown, see [6]. Other difficulties include severe sand issues leading to sticking and stuck pumps, and also sand settling leading to excessive wear and tear on the pump. Horizontal wells are extremely dynamic and must be approached using unconventional methods when possible.

In recent years, drilling longer laterals and utilizing new completion methods with more aggressive fracs has led to increased recovery in unconventional reservoirs, see [7], and therefore gained popularity. Along with these new drilling and completion techniques came issues such as fracture irregularities and pressure and permeability inconsistencies. Newer and recently completed wells often corkscrew and undulate in the lateral, causing difficulty when trying to produce these horizontal completions by causing slugging tendencies, liquid hold up, heading, and inconsistent unloading. For example, imagine 10 vertical wells with 20-acre spacing, all drilled at the same time and at the same depth in the same reservoir. There could be a variation in reservoir pressure of 1500-2500 psi, with a permeability range of 2-20 mD. Though matched on some parameters, these 10 vertical wells would not be identical and would need to be optimized on an individual basis. Now, imagine drilling one wellbore horizontally through the same size area and implementing a multi-stage frac. Though drilling might be made easier, the variations in reservoir pressure and permeability ranges would all be within one wellbore, making production optimization chaotic and impossible to successfully address.

Other difficulties when trying to produce horizontal wells include periods where the well is producing all gas or all liquid at various times throughout the day. These instances ultimately change the fluid gradient in the annulus and can cause heading up or flumping. Conventional design and automation practices such as pump fillage setpoints and down time are other issues that have been observed to have negative impacts on production when converting from ESP to rod lift in horizontal wells. Previously, pump fillage setpoints could be set around 75 to 85 percent in older, vertical applications, where inflows were much steadier and more consistent. With dynamic, varying inflows and inconsistent gas rates, these conventional practices are no longer as effective, and often setting pump fillage setpoints at these higher percentages leads to missed production, see [1]. In the past, the fewest number of cycles per day, without impacting production, was preferred, therefore downtime was often increased in order to give the well more time to build a larger fluid column in between cycles and also reduce the total number of cycles per day as well. Today's wells experience more sand production than older, conventional wells, so downtime can be detrimental. When the rod pump shuts down, sand can settle back down in the pump and eventually cause scoring on the barrel and the plunger, leading to a worn pump and eventually a pump failure. Aside from the challenges associated with operational practices and unideal wellbore characteristics, current methods of sand and gas separation provide limited assistance and are overall inefficient in today's dynamic horizontal wells.

Downhole sand separation technology has existed for many years, but the effectiveness of current sand mitigation technologies has long been questioned by operators. The WellWorx team has spent years working both with, and as operators themselves, in an effort to extend run life and reduce maintenance costs of both ESP and rod pump methods of artificial lift. Understanding the behaviors and effectiveness of current technologies has been paramount in developing the most effective methods of sand separation in the industry today.

Sand problems in artificial lift are growing increasingly worse as a result of mainstream completion techniques. Current prominent technologies include screens and vortex or centrifugal-style separators. The primary goal of sand screens is to catch or capture the sand particles in the screen, therefore eliminating flow through and resulting in damage to the pump. Several fundamental problems exist with this approach. One is the screens tend to quickly plug off, forcing the operator to either pull the well prematurely or perform well maintenance periodically to clear out the screens - both of which increase downtimes and well maintenance costs. The other problem with this solution is the screen itself and the effect on increasing gas interference problems. A key point observed through testing under rod pump conditions is that on the upstroke, the large gas bubbles can change form to smaller bubbles and move through the screen and become trapped within the ID of the separator, making them unable to escape on the downstroke. These trapped gas bubbles build up over time, eventually working their way into the pump intake.

Vortex or centrifugal-style separators have been observed to perform better, but still suffer shortcomings. The operational intent is to force the sand below the pump suction in a centrifugal motion at a velocity greater than the pump suction and on a path that 'hugs' the ID of the outer tube of the separator. Testing has proven these tools to effectively separate only 50 to 60 percent of the sand. In the case of these separators, 40 to 50 percent of the sand will continue through the pump. Field data also supports this conclusion, see Figure 1.

Some technologies require sizing relative to production rate in order to be effective. The problem with this theory is that production inflows through the pump (ESP or rod pump) are dynamic, especially in horizontal wells where slugging and erratic flows occur. Therefore, sizing relative to production rate is impossible. As production lowers over time, fluid velocity through the tool is reduced, further decreasing separation efficiencies. With rod pump systems, fluid only moves through the separator half the time at high velocity. On the downstroke, fluid moves much slower and can even become static. Because the sand discharge and pump suction are located in close proximity to each other, sand is inevitably sucked into the dip-tube on the upstroke and carried to the pump. Through testing and observation, it was learned that the centrifuges were too short in the current separators, which resulted in the prevention of proper centrifugal separation.

Yet another concerning issue is that the outer tubes of the separators were not built to withstand erosion and corrosion effects, resulting in the tools parting, which further resulted in retrieval problems as the separator and mud joints had often fallen to the bottom of the wellbore.

Aside from sand separation issues, mitigation of gas interference poses another threat when trying to produce horizontal wells. Over the years, many types of gas separators have been developed and utilized including natural separators (pumping below the perforations), poor boy-type separators, packer-style separators, tail pipe applications and other experimental systems.

In many vertical wellbores, natural gas separation is easily achievable by placing the rod pump below the producing interval. In this case, gas and liquids flow into the wellbore through the perforations – the heavier, denser liquids fall downward towards the bottom of the wellbore and enter the pump intake, while the lighter, less dense gas naturally rises up the casing annulus. This is the ideal condition, as almost no gas will enter the pump intake, see [2]. However, in horizontal and deviated wells, and also vertical wells without enough rathole, this scenario is impossible and therefore a gas separator must be used.

Commonly in vertical applications where the rod pump cannot be placed below the perforations or even some horizontal wells experiencing lower production, a poor boy-type gas separator is used, see [2]. The poor boy-type gas separator consists of a perforated or slotted sub, typically the same OD as the production string, and a 20’ dip tube, usually 1” or 1-1/4” in diameter. As gas and liquids enter the wellbore through the perforations, a fluid column builds in the casing annulus, eventually reaching the perforations or slots of the sub. Wellbore fluids then enter the slots and fall downwards towards the dip tube, where the liquids then enter and travel upwards to reach the pump intake. Gas theoretically takes the path of least resistance and travels upwards through the casing, rather than changing direction to enter the perforations or slots of the poor boy-type separator. A larger version of the poor boy-type gas separator is often referred to as a ‘mother hubbard’ or ‘modified poor boy’. In this case, the outer tube of the separator is larger than the production tubing, usually 3-1/2” when used in 5-1/2” casing. A larger outer tube is preferred to create more cross-sectional separation area within the separator, and therefore reduce downward fluid velocities and increase separation efficiencies. Though cross-sectional separation area is increased with this type of separator, it is still limited due to the size of separator that can be ran through the casing. This limitation leads to a reduced fluid volume that the separator is able to effectively separate, therefore limiting overall the separation efficiency, see Figure 2.

One way to overcome the lack of cross section separation area is to utilize a packer. In the case of packer-style separators, all gas and liquids enter the separator below the packer through an intake. Gas and liquids then travel upward through the separator where they are then expelled out into the casing-tubing annulus. Heavier, denser fluids fall back down in the casing-tubing annulus, eventually entering a dip tube and traveling upwards to the pump intake, while lighter, less dense gas rises up the casing-tubing annulus. Here, by using the casing-tubing annulus, the cross-sectional separation area is increased, leading to a reduction in downward fluid velocity and increasing the overall efficiency of the separator.

According to [4], packer style separators were proven to show better performance in unconventional wells than non-packer style.

To date, the packer-style separator has proven to be the most effective for horizontal wells, but significant problems commonly arose. One such problem was that despite utilizing the casing-tubing annulus for cross sectional separation area, higher production rates led to increased downward fluid velocities, therefore effective gas separation could not occur. Other issues that commonly occurred were related to the packer. While an improperly set packer is problematic on its own, sticking packers and anchor packer combinations are considered risky due to large sand fracs. And although these traditional packer-style separators have been considered the most effective form of downhole gas separation, they presented recovery issues when combined with a conventional packer. Often conventional packers would become difficult to retrieve or stuck, causing the tool to part, therefore creating a costly fishing job. These issues often outweighed the efficiency gains of the tool and forced operators to run less effective gas separators. The team at WellWorx set out to develop a packer-style separator that minimized the risk of running a packer and maximized the cross-sectional separation area.

OBJECTIVES

WellWorx has designed a sand separator that performs regardless of production rates and is effective with even the smallest mesh sands. The main objective is to move and confine the sand in its own unique flow path and to discharge the sand away from the pump suction.

As mentioned, WellWorx also set out to maximize the cross-sectional separation area between the OD of the gas separator and the ID of the casing to maximize effective downward fluid velocities. Another main goal is to obtain low recovery risks like that of a poor boy, but still maintain the effectiveness of a packer style separator. WellWorx achieved this while maintaining acceptable tensile strengths, reducing turbulence and utilizing high quality machined parts. Lastly, WellWorx aimed to protect the pump intake through the use of a shroud, should there be any gas leaking by a damaged or improperly set packer. Hence, the Super Max was born, see Figure 3.

DESIGN OF NEW TECHNOLOGY

The Super Max is composed of a dual-channel, centrifugal vortex with a sand bypass tube, see Figure 4. The outer tube is nine feet in length with a 3.75 inch OD and a 3 inch ID. The inner tube has a 2.375 inch OD with a 1.99 inch ID. The centrifuge is one foot long and consists of two flow channels of different pitches. The sand bypass tube is three feet long with a .675 inch OD and an ID of 0.493 inches (3/8" nominal OD).

The ESP version is ceramic coated on the ID and OD of the tool body, includes nickel coated pins, and a stainless-steel inner tube to mitigate erosion and corrosion. This version is also recommended for harsh rod pump environments to prevent sand erosion caused by higher fluid velocities. The metallurgy, wall thickness, and erosion mitigation measures are designed to ensure tool performance with a minimal risk of failure.

The sizing and design of the dual-channel centrifuge allows for proper and effective sand separation regardless of production rate. The upper channel uses natural gravity to encourage sand to drop into the lower channel. While in the lower channel, it is extremely difficult for sand to migrate back up into the upper channel. This captures all sand in the lower channel, which then feeds directly into the sand drain and eventually the sand bypass tube. The sand bypass tube then discharges solids directly into the mud joints and separates the pump intake from the sand discharge point by three feet. The sand bypass tube is centered within the tool to prevent a "spoiler" effect, allowing the vortex of fluid to continue around the bypass tube. This allows any sand that was not captured in the sand bypass tube to continue the same flow path without disruption, increasing the chances that any remaining particles will fall and settle into the mud joints as well.

The Super Max utilizes a dual HNBR cup technology (NR-1) that effectively sumps the pump while reducing the risk of a stuck packer. By utilizing two inverted cups to seal the wellbore and eliminating any setting and unsetting mechanisms, this risk of sticking the packer is eliminated. The weight of the fluid level above the top cup pushes down on the cup and creates the top seal. The inflow from the reservoir pushes up on the bottom cup, creating the bottom seal. The Super Max uses HNBR because of the material's resistance to abrasion, which is an important factor when running the packer in and out of the hole. In order to ensure the best seal possible, a casing scraper run is recommended prior to running the Super Max. This practice is especially important in older wells that have already been producing for a few years. Also, in order to prevent damage to the packer cups, it is recommended for the rig operator to run in the hole at a speed slower than 60 feet per minute. As an added ‘safety factor,’ the Super Max features a 4” x 20” shroud. This shroud on the OD of the tool protects the tool’s intake from any gas that does manage to leak by a damaged or improperly set packer.

The Super Max is designed to create the greatest tool OD to casing ID ratio possible, allowing for a maximized cross sectional separation area in the annulus of the given wellbore. The Super Max is composed of a 1.9” tool OD for a full 40’ length. By utilizing a 1.9” tool OD, the Super Max increases the cross-sectional separation area inside the casing-tubing annulus, and therefore decreases the downward velocity of the fluid prior to pump entry, allowing gas to escape naturally up the casing. For gas separation to occur, this downward fluid velocity must be slower than the bubble rise velocity. Assuming a maximum gas bubble rise velocity of 0.4 ft/sec, the formulas below can be used to calculate total pump displacement or barrels of fluid per day that can be effectively separated before “overrunning” the separator, meaning at this point the downward fluid velocity would exceed the bubble rise velocity and separation efficiencies would be reduced.

$$\text{Downward Fluid Velocity } \left(\frac{ft}{sec}\right) = \frac{0.0119(\text{Total Pump Displacement}, bpd)}{(\text{ID}^2, in - \text{OD}^2, in)}$$

$$\text{Total Pump Displacement } (bpd) = \frac{(\text{Downward Fluid Velocity }, ft/sec)(\text{ID}_{csg}{}^2, in - \text{OD}_{sep}{}^2, in)}{0.0119}$$

$$\text{Total Pump Displacement } (bpd) = \frac{(0.4\ ft/sec)(4.778^2, in - 1.9^2, in)}{0.0119}$$

$$\text{Total Pump Displacement } (bpd) = 646\ bfpd$$

In this example, we have used 5.5”, 20# casing (4.778” ID), which results in a maximum total pump displacement of 646 barrels of fluid per day. It is worth noting that this is a simple downward fluid velocity calculation and does not consider dynamic inflows. Once a well starts slugging, the reservoir is giving up all gas or mostly all gas and therefore the rod pump will still experience gas interference even if the well is below the production limits of the separator. This same exercise can be repeated using varying casing ID’s and tool OD’s for packer-style separators and outer tube ID’s and inner tube OD’s of poor boy separators, see Figure 2. More details on the above theory can be found in [3].

By optimizing metallurgies, the Super Max maintains a high tensile strength of 80,000 psi for varying wellbore conditions. During tool testing, the Super Max demonstrated superior separation efficiencies with a 20 percent increase in separation efficiency compared to other technologies. This directly results in improved pump performance in rod pump wells.

SIMULATOR TEST RESULTS

Testing and evaluations of sand separators was conducted by constructing a well simulator. Testing included the sand separator portion of the Super Max and two industry-standard vortex sand separators. Testing also included sand of varying mesh sizes and differing production rates. Screen type separators were not included in the test due to the above-described tendencies to plug off.

As can be seen in Figure 1, when compared to industry standard technologies, the desander portion of the Super Max performed with an efficiency of 95 percent compared to 50 and 55 percent for the other technologies. These results coincide with other studies previously conducted, suggesting that separator design and pumping unit speed can reduce efficiencies to lower than 50 percent, see [5].

CALCULATED RESULTS AND CONCLUSIONS

Through use of simple calculations and the equations described above, the different types of gas separators can easily be evaluated. When the cross-sectional separation area is increased, the fluid volume is also increased, thus proving the importance of maximizing the separation area for greater gas separation efficiencies. Without question, the packer-style separators create the largest cross sectional separation area by utilizing the casing-tubing annulus, rather than the tool's dimensional differences. As seen in Figure 2, when compared to other industry standard technologies, the 1.9" Super Max allows for a maximum fluid volume of 646 bfpd before separation efficiencies become hindered. This is a greater fluid volume than any other tool on the market due to the maximized tool OD to casing ID ratio that the Super Max boasts.

FIELD RESULTS

The pairing of the larger, dual-channel vortex and a three-foot separation between discharge and pump intake points has proven to be more effective than originally anticipated during design. Maximizing the separation area between the casing ID and the tool OD, coupled with the use of the shroud, has also proven to be beneficial. In the past year, hundreds of Super Max systems have been deployed across all U.S. basins as well as in Canada.

For the following case studies, all wells are horizontal completions, 5-1/2" 20# production casing, 2-7/8" tubing, ESP to rod pump conversions.

Figure 5 illustrates our first case study utilizing the Super Max separator. The Super Max separator was installed in this well on January 28, 2021. This well utilizes an R-320-360-288 pumping unit and an 878 rod string design with a 2.25" pump. Prior to the conversion, this well experienced a fair amount of downtime due to the ESP repeatedly going down for motor temperature. There was also a facility repair made prior to the conversion, which impacted production. After the conversion to rod pump, a week of severe weather was experienced and the field went down. After the field came back online, oil, gas, and water production were able to recover. It is shown that oil production stayed on trend after the conversion to rod pump and, over time, gas production climbed back up to rates similar to those experiences when the well was on ESP. On June 6, 2021, a surface failure was noted, thus the reason for the small dip in production around this time period and a few days of bad weather later the same month. Figure 6 illustrates data from the pump off controller on the same well as described in Figure 5. As shown, this well typically runs 24 hours a day (100 percent runtime) at an average of 4 SPM and nears 100 percent average pump fillage. Inferred production numbers remain around 500 bfpd on average for this well, which is consistent with the actual production. Figure 7 shows downhole cards over time for this well. As shown, this well is experiencing full cards before eventually experiencing slight fluid pound. There is little to no evidence of gas compression in the downhole cards. Overall, it can be said that the Super Max separator in this well has aided in sufficient gas and sand separation, therefore contributing to a successful drawdown with little to no downtime on this well.

Figure 8 illustrates another ESP to rod pump conversion utilizing the Super Max separator. In this example, the Super Max separator was installed on February 2, 2021. This well utilizes a C-912-427-192 pumping unit and a mixed rod string composed of fiberglass rods, 7/8" steel rods, and 1-1/2" sinker bars with a 1.75" pump. Again, the field becomes shut down during severe winter weather shortly after the conversion. After the field comes back online, both oil production and water production steady out. In this example, gas production dramatically increases after the conversion to rod pump. Again, oil production rates are comparable to those exhibited when the well was on ESP. Another time period of lost production is noted in June 2021 due to weather. Figure 9 shows data from the pump off controller on the same well as described in Figure 8. This well runs 24 hours a day (100 percent runtime) at an average of 7 SPM and hovers around 80 to 85 perent average pump fillage. This well does have a high gas production rate, sometimes climbing upwards of 550 mcfpd, therefore pump fillage is more erratic than was shown on the previous example. The inferred production averages around 400 bfpd, which is higher than the actual production shown for this well. This difference can be accounted for because of the inconsistent gas rates this well experiences. Figure 10 shows downhole cards over time for the same well as described in Figure 8 and Figure 9. As previously thought, this well is experiencing slight gas interference at times, but fluid pound as well. As mentioned, this well has a high gas production rate and often experiences gas slugging tendencies. These dynamic horizontal wells often experience periods of slugging, therefore if the well is only slugging gas during this time, gas will enter the pump, causing the gas interference shown.

Figure 11 details an ESP to rod pump conversion that again utilizes the Super Max separator. In this example, the Super Max was installed on February 8, 2021. This well utilizes a C-912-365-192 pumping unit with an 87 rod string design, 1-1/2" sinker bars, and a 1.75" pump. As shown in previous examples, there is lost production due to severe weather in February 2021 and in June 2021. Again, it can be noted that over time, all production (oil, gas, and water) rates become comparable to those shown prior to the conversion. Figure 12 shows data from the pump off controller on the same well as described in Figure 11. As shown, this well typically runs 24 hours a day (100 percent runtime) at an average of 7 SPM and averages 80-90 percent pump fillage. As the well draws down, more gas is being produced, therefore pump fillages become more irregular. Inferred production numbers also begin to trend downward from ~350 bfpd to around ~300 bfpd on average as well, which is about ~50 bfpd higher than actual total fluid production. Figure 13 illustrates downhole cards over time for the same well as described in Figure 11 and Figure 12. As shown, this well is experiencing nearly full cards before eventually experiencing slight fluid pound. There is little to no evidence of gas compression in the downhole cards.

CONCLUSION

These case studies help to suggest that if the rod pumping system is properly designed and utilizes the Super Max separator, we do not have to accept less production when converting from ESP to rod pump and, often, the economics are beneficial if production can be maintained. When operators and vendors work together to understand the challenges, optimal results are attained, and in some cases, total production has been increased.

The Super Max demonstrates superior separation efficiencies with a 20 percent increase in separation efficiency compared to other technologies. This directly results in improved pump performance in rod pump wells.

Without question, the Super Max has the largest cross-sectional separation when compared to other technologies and allows for a maximum fluid volume before separation efficiencies become hindered. This is a greater fluid volume than any other tool on the market due to the maximized tool OD to casing ID ratio that the Super Max boasts.

ACKNOWLEDGMENTS

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FIGURES

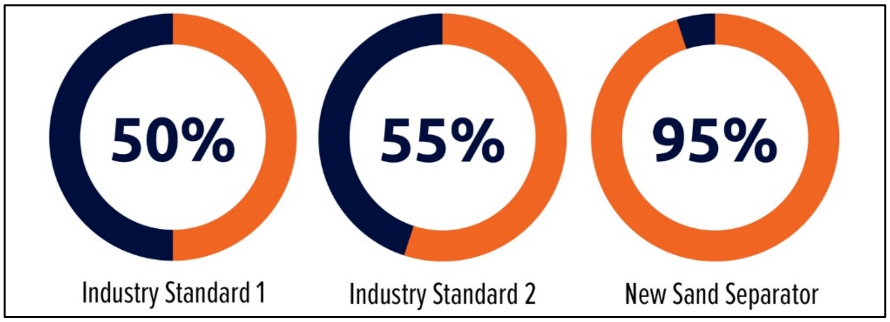

FIGURE 1: Separation efficiency of Super Max compared to industry standard.

Casing Size	Tool	Cross Sectional Separation Area $\pi(R^2-r^2)$	Separation Area (in^2) (D^2-d^2) For volume calculation	Fluid Volume, bfpd
5.5"	**2-3/8" Poor Boy**	2.26	2.88	**97**
5.5"	**2-7/8" Poor Boy**	3.32	4.23	**142**
5.5"	**3-1/2" Mother Hubbard (A)**	6.03	7.68	**258**
5.5"	**3-1/2" Mother Hubbard (B)**	6.53	8.31	**279**
5.5"	**4.125" WellWorx Halo**	9.45	12.04	**405**
5.5"	**3.5" Packer Style Separator**	8.47	10.79	**363**
5.5"	**2-7/8" Packer Style Separator**	11.60	14.77	**497**
5.5"	**2-3/8" Packer Style Separator**	13.67	17.40	**585**
5.5"	**1.9" SuperMax**	15.09	19.22	**646**

FIGURE 2: Comparison of cross sectional separation area for existing gas separators.

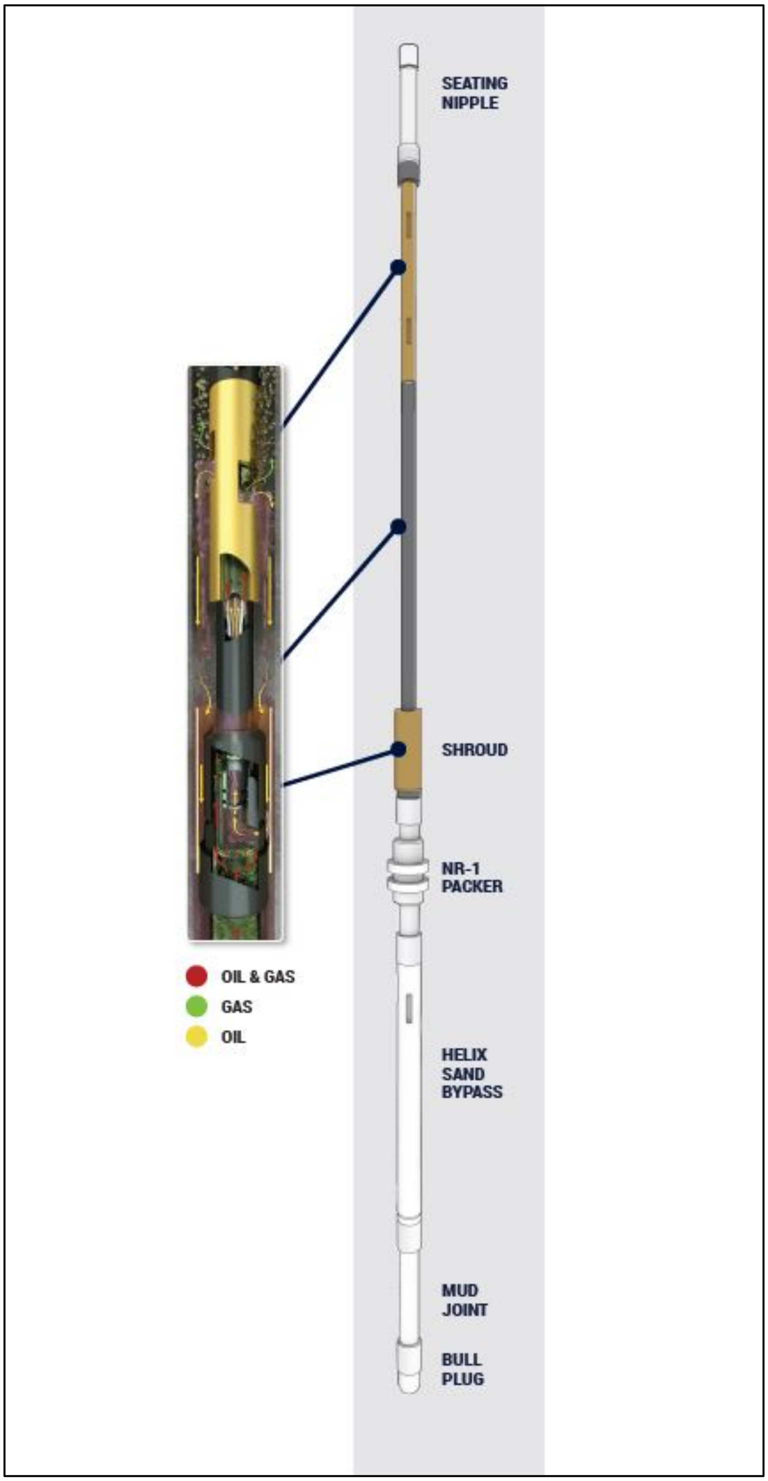

FIGURE 3: Illustrates a complete view of the Super Max as well as a detailed look at the flow pattern of fluids throughout the tool. As shown, fluids first enter the sand separator portion of the Super Max, located below the NR-1 cup-type packer. Solids are then deposited into the mud joints, while fluid enters the ID of the packer and travels upwards inside the Super Max for a full 40 feet. Fluids are then expelled into the casing-tubing annulus where gas continues to rise up the casing annulus and fluids fall 40 feet back down to catch in the shroud. Once in the shroud, gas-free fluid enters the dip tube and rises back up, eventually entering the pump intake.

FIGURE 4: Illustrates an in-depth look at the sand separator portion of the Super Max. As shown, the dual-channel spiral encourages heavier sand particles to fall into the lower channel, while lighter fluids are retained in the higher channel. Solids are then funneled into the sand drain and eventually fall into the sand bypass tube, where they are then deposited into the mud joints. Fluid exits the bottom of the centrifuge and enters the pump suction.

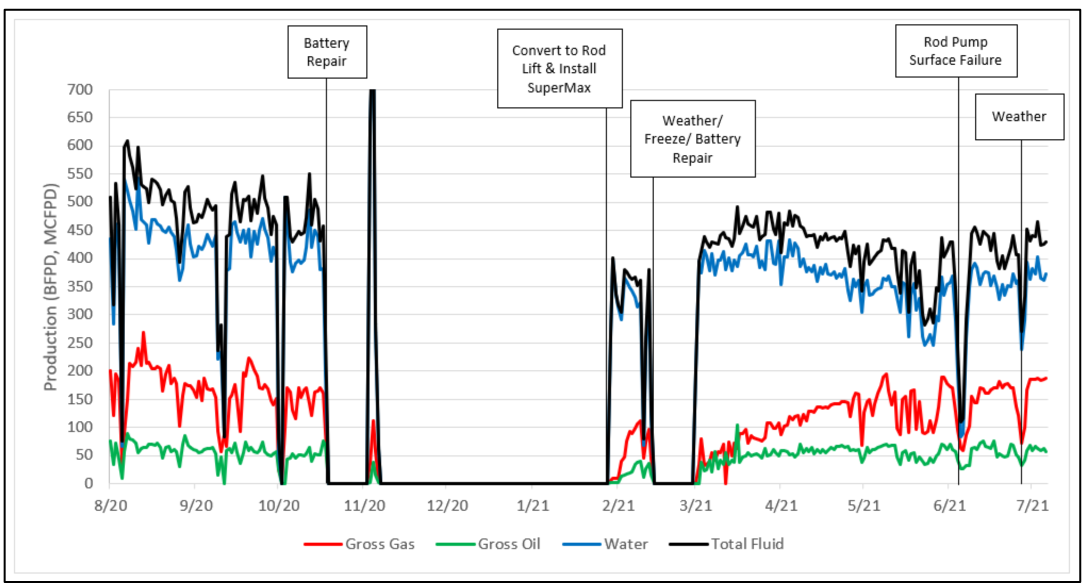

FIGURE 5: Illustrates an ESP to rod pump conversion utilizing the Super Max, installed on January 28, 2021. As shown, oil production stays on trend after the conversion to rod pump and over time, gas production climbs back up to rates similar to those when the well was on ESP.

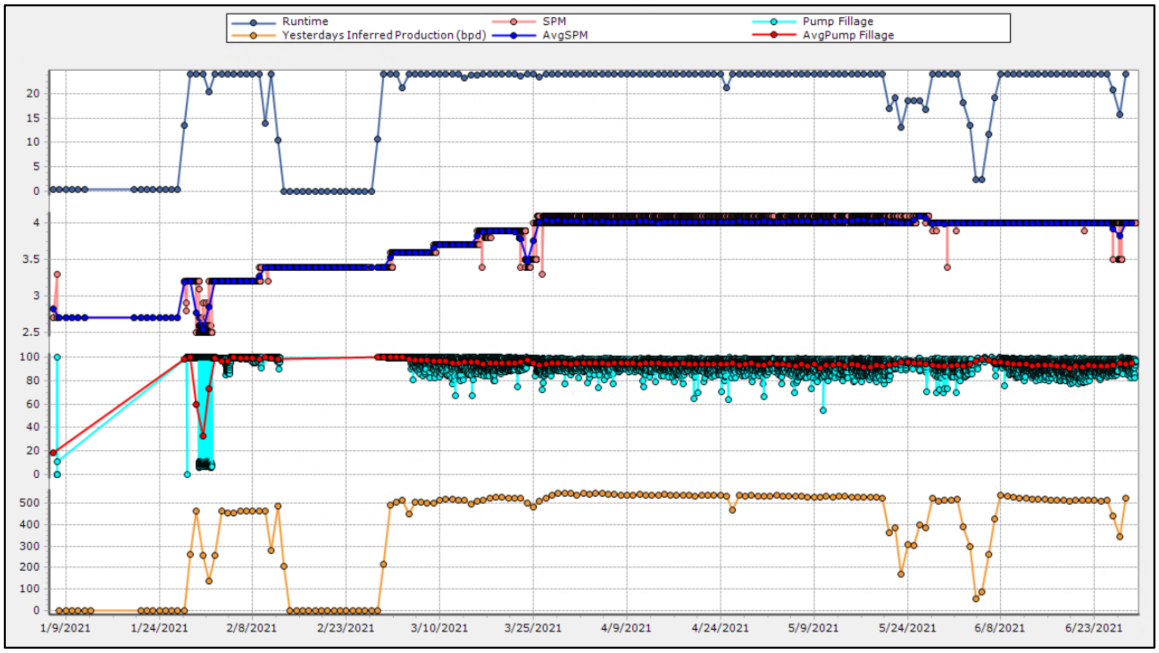

FIGURE 6: Shows data from the pump off controller on the same well as described in Figure 5. As shown, this well typically runs 24 hours a day at an average of 4 SPM and nears 100 percent average pump fillage. Inferred production numbers stay around 500 bfpd on average as well.

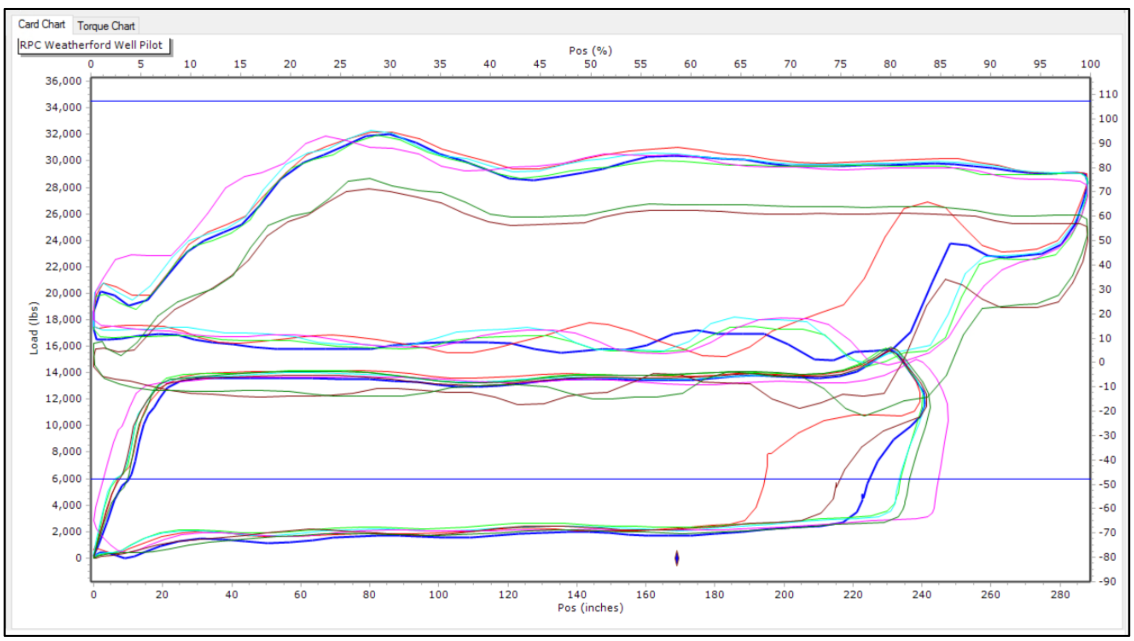

FIGURE 7: Illustrates downhole cards over time for the same well as described in Figure 5 and Figure 6. As shown, this well is experiencing full cards before eventually experiencing slight fluid pound. There is little-to-no evidence of gas compression in the downhole cards.

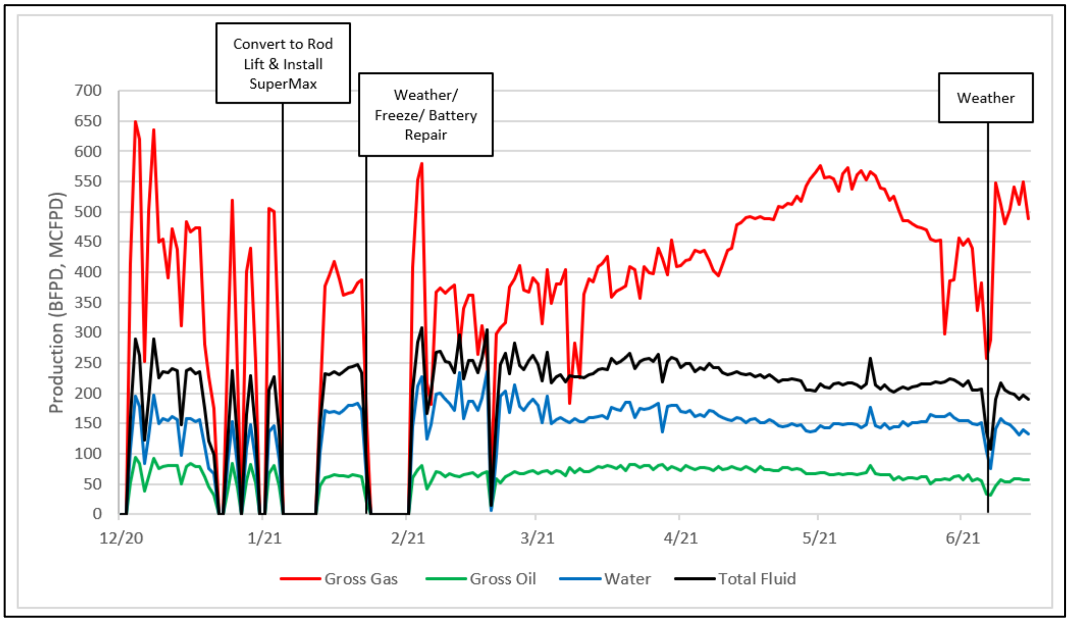

FIGURE 8: Illustrates another ESP to rod pump conversion utilizing the Super Max separator. In this example, the Super Max separator was installed on February 2, 2021. After a production loss due to severe weather, both oil production and water production steady out. In this example, gas production dramatically increases after the conversion to rod pump. Again, oil production rates are comparable to those exhibited when the well was on ESP.

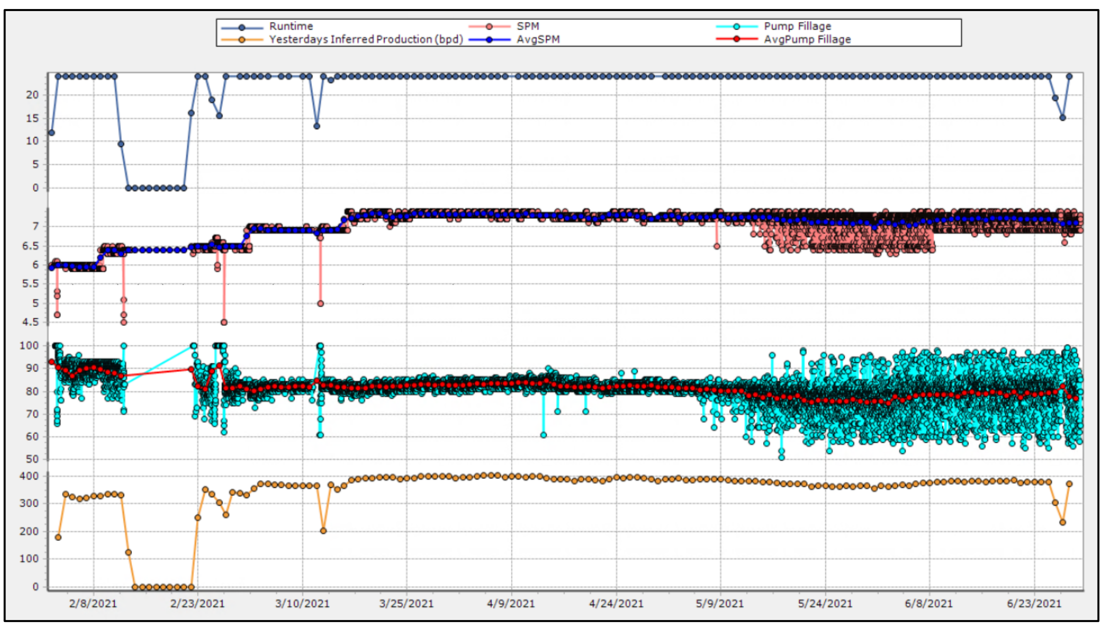

FIGURE 9: Shows data from the pump off controller on the same well as described in Figure 8. This well runs 24 hours a day (100 percent runtime) at an average of 7 SPM and hovers around 80-85 percent average pump fillage. This well does have a high gas production rate, sometimes climbing about 550 mcfpd, therefore pump fillage is more erratic than was shown on the previous example. The inferred

production on this well averages around 400 bfpd, which is higher than the actual production shown for this well.

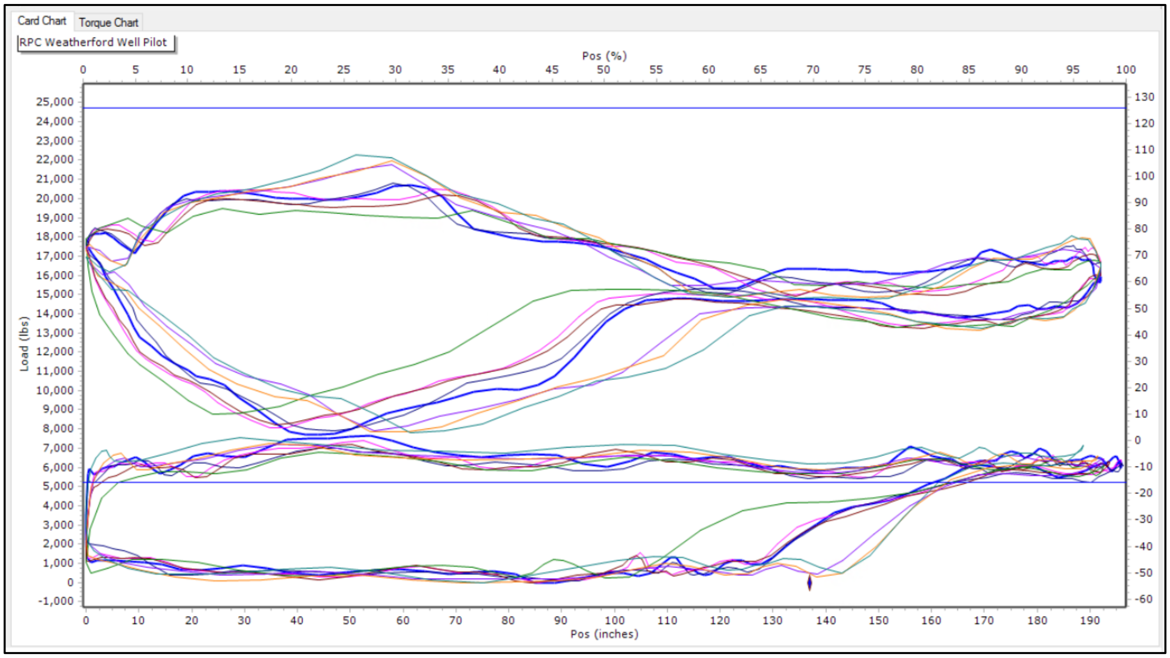

FIGURE 10: Shows downhole cards over time for the same well as described in Figure 8 and Figure 9. As shown, this well is experiencing slight gas interference at times, but also fluid pound as well. As mentioned, this well has a high gas production rate and often times experiences gas slugging tendencies.

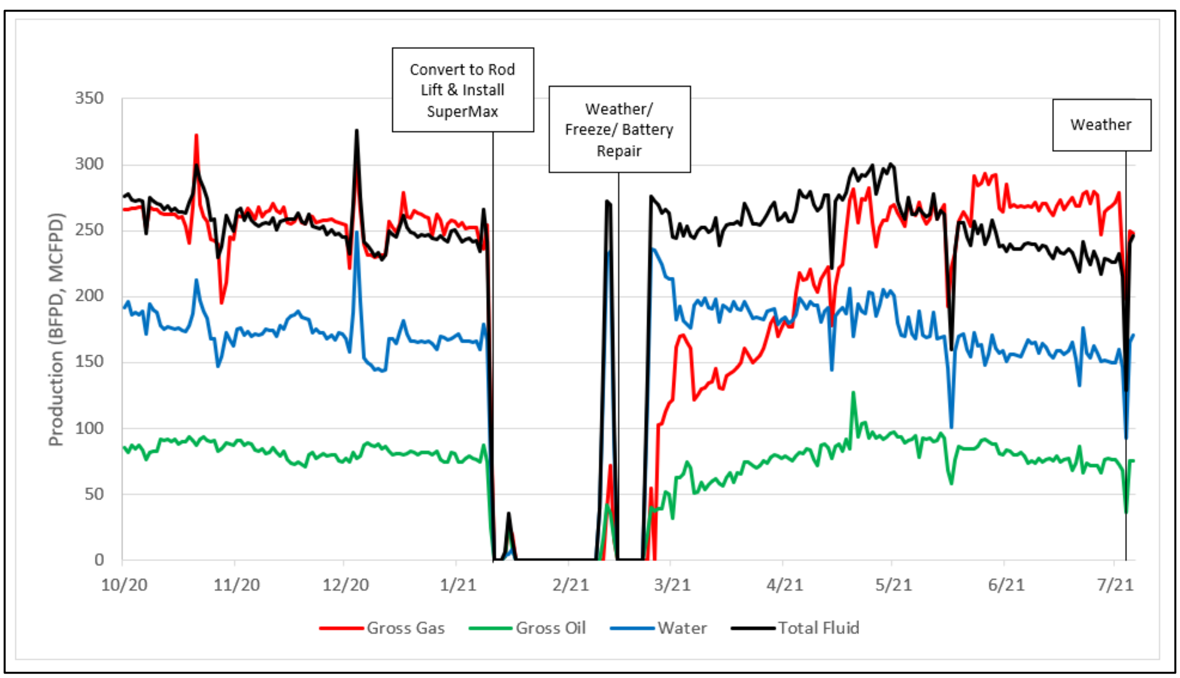

FIGURE 11: Details an ESP to rod pump conversion that again utilizes the Super Max separator. In this example, the Super Max separator was installed on February 8, 2021. Again, it can be noted that over time all production (oil, gas, and water) rates become comparable to those shown prior to the conversion.

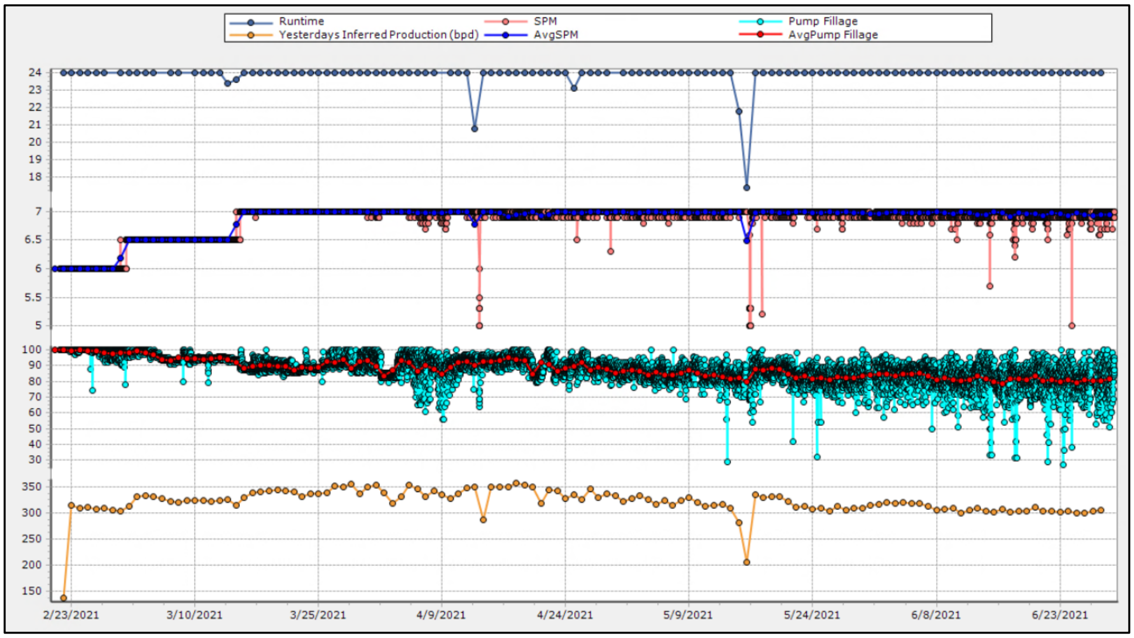

FIGURE 12: Shows data from the pump off controller on the same well as described in Figure 11. As shown, this well typically runs 24 hours a day at an average of 7 SPM and averages 80-90 percent pump fillage. As the well draws down, more gas is being produced, therefore pump fillages become more irregular. Inferred production numbers also begin to trend downward from ~350 bfpd to around ~300 bfpd on average as well.

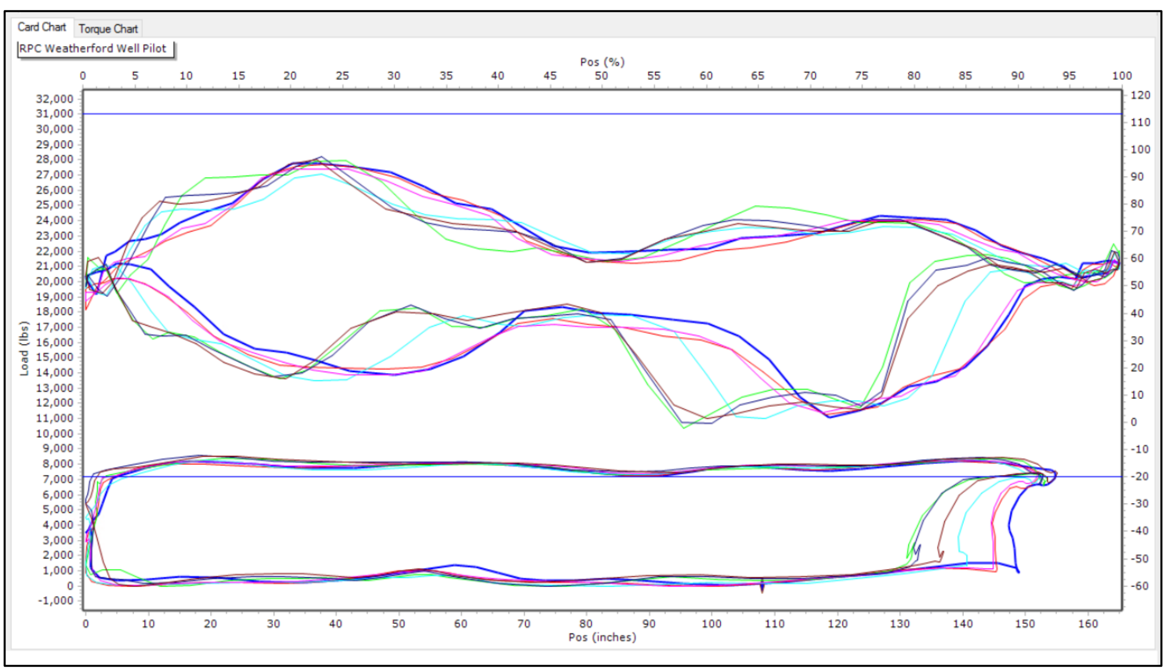

FIGURE 13: Illustrates downhole cards over time for the same well as described in Figure 11 and Figure 12. As shown, this well is experiencing nearly full cards before eventually experiencing slight fluid pound. There is little to no evidence of gas compression in the downhole cards.