10 YEARS PUMPING BELOW KICKOFF POINT

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ABSTRACT

The contemporary rod pumping strategy for horizontal wells typically involves placing the pump at or above the Kickoff Point (KOP) to ensure the rod string and downhole pump operate in relatively low dogleg severity conditions. However, in certain types of reservoirs and well conditions, it may be beneficial to place the pump below the KOP. This paper presents a case study from Devon Energy's Powder River Basin and Delaware Basin assets, where over the past decade, more than 1400 pumps have been operated below the KOP in over 400 unique wells. The study examines the conditions, methodologies, and outcomes associated with this approach, highlighting its potential advantages, operational insights, and recommended best practices.

INTRODUCTION

Over the past two decades, the number of horizontal rod-pumped wells operated by Devon Energy has increased significantly, from fewer than 50 to over 2,300 today. While most of these wells have been operated with the pump landed at or above the KOP, approximately 16% have been operated with the pump landed below the KOP. The focus of this paper is on those wells, which are distributed across multiple basins and formations, each presenting unique characteristics and challenges. The paper discusses individual well examples, design evolution and specifications, and run time statistics.

PROBLEM STATEMENT

Pumping horizontal wells presents unique challenges due to the inability to place the pump below perforations, as shown in figure 1. Consequently, the system must manage gas separation and pump-off differently than vertical wells. This often results in a persistent state of incomplete or inconsistent pump fillage for 2 primary reasons:

1. **Gas Interference Due to Limited Gas Separation:** The limited ability to effectively separate gas from liquid leads to gas interference.
2. **Fluid Pound in Pumped-Off Conditions:** Every horizontal well eventually reaches a pumped-off condition, leading to fluid pound.

To maintain production rates while pumping from the KOP, operators often install rod pumping systems designed to displace more fluid than the reservoir can consistently deliver to KOP. Efforts to reduce pumping speed or design to precisely match inflow frequently result in a loss of production due to the exacerbation of slugging issues during liquid loading and unloading between the pump intake and the lateral section.

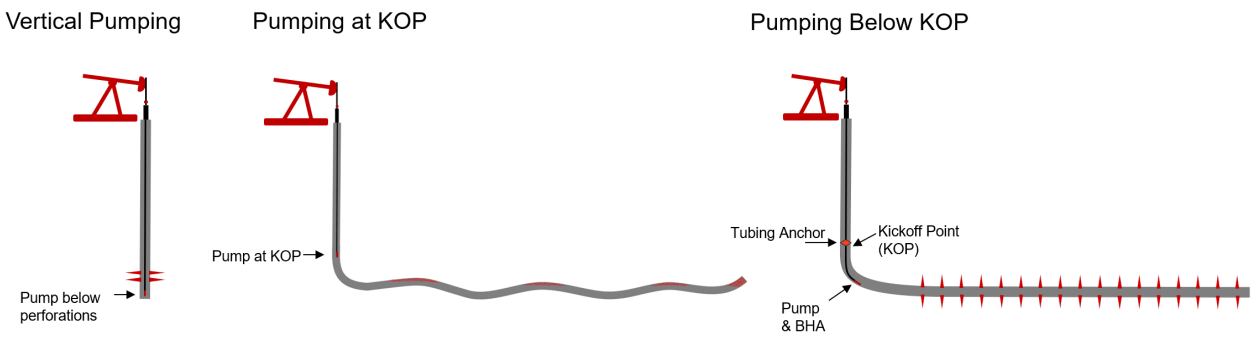

Figure 1. – Rod Pumping Evolution

While initially placing the pump below the KOP was intended to address the issue of pump-off, benefits in gas separation have been observed in wells producing both small and large volumes of fluid. This can be attributed to the fact that the gas separator and pump intake lay on the low side of the production casing when landed below KOP. Consequently, a natural separation occurs due to gravity, as illustrated in Figure 2.

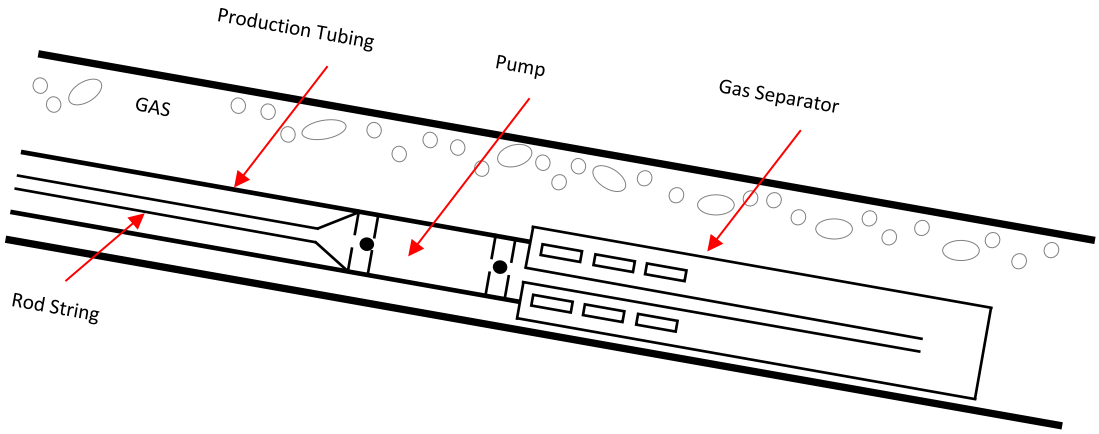

Figure 2. - Gas Separation Effect at High Inclination

Figure 3 shows that from 2011 to 2016, pumping below the KOP was not widely implemented in most areas. The ramp-up from 2017 to 2019, followed by a subsequent drop-off, highlights the large number of pumps that were lowered in the Powder River Basin (PRB) and Delaware Basin during this period. The decrease in installs in the Powder River Basin in recent years is due to the lack of failures and long run times of these installations. In contrast, the decrease in installs in the Delaware Basin can be attributed to the higher failure rate experienced there, leading to pumps being raised back to the KOP due to short run times. Notably of the 180 Delaware Basin wells initially pumped below KOP, only 60 today remain operating with pumps set below KOP. The challenges associated with pumping below the KOP in the Delaware Basin, along with recommendations to overcome them, are addressed in subsequent sections of this paper.

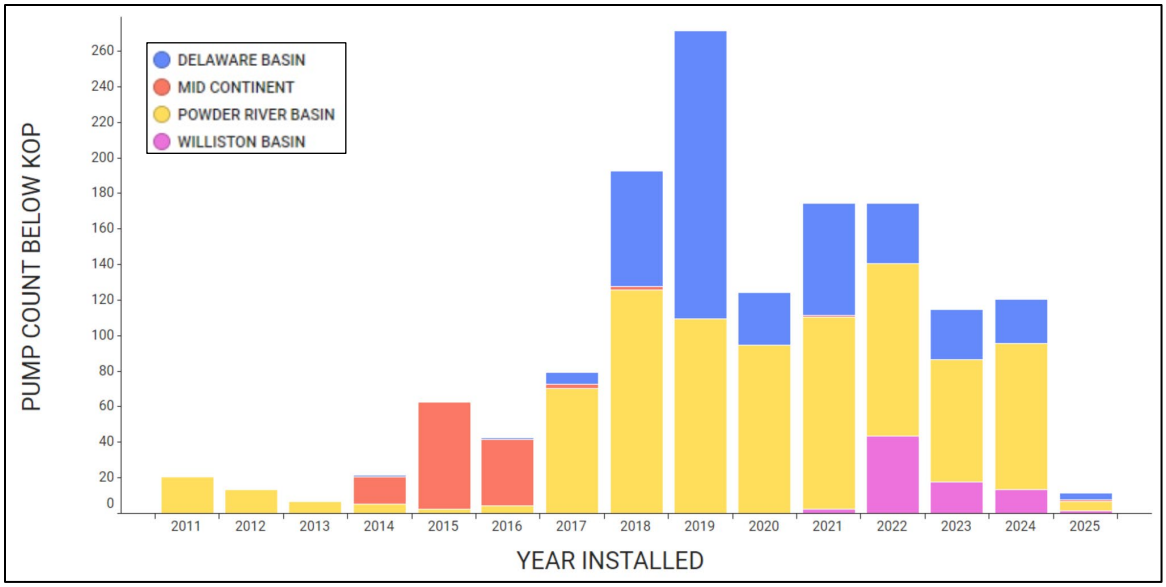

Figure 3. Pumps Installed Below KOP by Year

POWDER RIVER BASIN – EARLY EXAMPLES

Early examples of pumping below KOP were limited due to the small number of horizontal wells needing rod lift operated by Devon prior to the early 2010s. Some of the first examples of pumping below KOP happened in the Powder River Basin, specifically in low volume horizontal wells producing from the Parkman Sandstone.

PRB example well #1 (below) is one such example from 2011. Wellbore construction consisted of 7” casing and a 4.5” liner set at KOP. The initial tubing string installed in 2011 consisted of a mixture of 2 7/8” L80 tubing and poly lined 2 7/8 tubing above and below the tubing anchor (tubing anchor at KOP) with 2 3/8” tubing run through the curve section and inside the 4.5” liner. Seating nipple was set at 70 degrees.

This design utilized a 76 taper without sinker rods as shown in Table 1.

JT #	DESCRIPTION	LENGTH	TOTAL LENGTH	BTM INCLINATION
1	KB	25.00		
162	2 7/8 Tubing	5,017.72	5,042.72	1.58
38	2 7/8 Poly Lined Tubing	1,196.59	6,239.31	27.20
1	Anchor/Catcher	2.33	6,241.64	27.41
2	2 7/8 Poly Lined Tubing	62.94	6,304.58	32.71
1	Cross Over	0.75	6,305.33	32.77
18	2 3/8 Tubing	555.95	6,861.28	65.69
1	Seat Nipple - Cup Type	1.10	6,862.38	65.69
1	2 3/8 Slotted Joint	31.31	6,893.69	69.31
1	2 3/8 Mud Joint	30.90	6,924.59	69.03

Rod	Description
1	1 1/2" SM PR
3	4', 6', 8' Slick 7/8 Ponies
105	7/8" Slick S88 Rods
110	3/4 Slick S88 Rods
36	7/8 Slick S88 Rods
20	7/8 S88 - 4 GPR
1	3' 7/8' Stabilizer Rod
1	1 1/2" Insert Pump

Table 1.

After an initial 4 year run the well was worked over, the poly lined tubing was removed, and the rod string was modified as shown in table 2. The second pump ran for 5 years until it was replaced for wear in 2020. The same tubing string has been installed in this well for over 10 years.

JT #	DESCRIPTION	LENGTH	TOTAL LENGTH	BTM INCLINATION
1	KB	25.00		
200	2 7/8 Tubing	6,214.88	6,239.88	27.25
1	Anchor/Catcher	2.33	6,242.21	27.49
2	2 7/8 Tubing	62.94	6,305.15	32.75
1	Cross Over	0.75	6,305.90	32.81
18	2 3/8 Tubing	555.95	6,861.85	69.65
1	Seat Nipple - Cup Type	1.10	6,862.95	69.65
1	2 3/8 Slotted Joint	31.31	6,894.26	69.32
1	2 3/8 Mud Joint	30.90	6,925.16	69.02

Rod	Description
1	1 1/2" SM PR
3	4', 6', 8' Slick 7/8 Ponies
143	7/8" Slick S88 Rods
77	3/4 Slick S88
32	1" S88 - 4 GPR
26	7/8 Slick S88 - 4 GPR
1	3' 7/8' Stabilizer Rod
1	1 1/2" Insert Pump

Table 2.

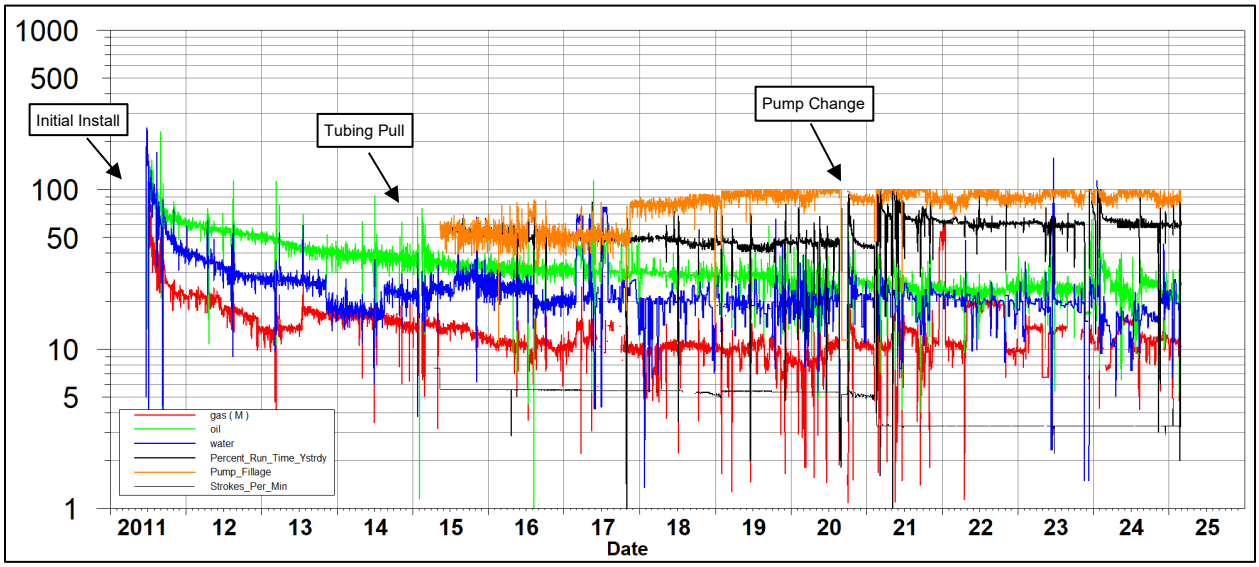

Figure 4. Powder River Basin Example Well #1

One factor contributing to the exceptionally long run times seen in this type of PRB well is the use of idle time in the pump-off controller (POC). Idle time is less frequently utilized in horizontal wells compared to vertical wells, due to the well dynamics mentioned earlier in this paper. The ability to implement idle time in late life wells without causing additional failures or lost production is an observed benefit of landing the pump below KOP. Below are two examples of idle time settings for summer and winter conditions in Wyoming for PRB example well #1. Shorter idle time is used to prevent freezing issues at surface during winter months.

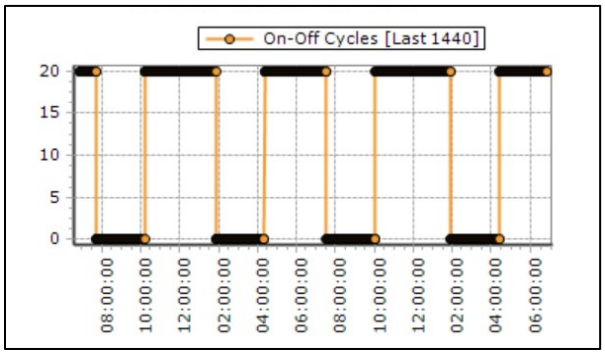

Figure 5. Summer Idle Time

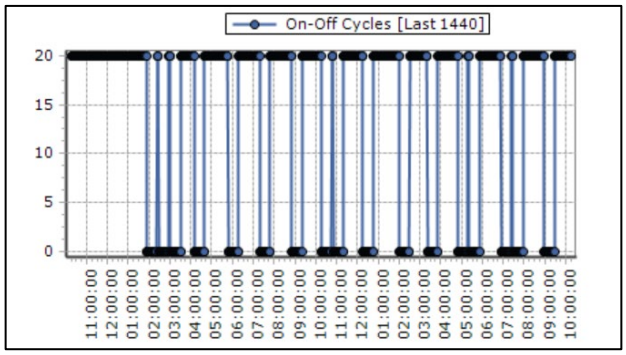

Figure 6. Winter Idle Time

POWDER RIVER BASIN – RAMP UP

Between 2017 and 2018, 120 Parkman and Teapot wells were worked over preemptively to lower pumps below KOP. The driver behind this decision was the realization that significant uplift potential existed given the conventional nature of these formation(s). Notably, the 0.1 to 1 millidarcy permeability in these formations is one to two orders of magnitude greater than that found in most unconventional oil plays currently under development in North America.

FROM PUMP AT KOP TO PUMP IN CURVE

Powder River Basin example well #2 was initially converted to rod pump in December 2015, with the pump placed at the KOP. As is common in many horizontal wells, the well struggled with pump fillage, and production tapered off as a result, falling far below the rates achieved while producing on ESP. In October 2016, the tubing was pulled, and the tubing anchor was swapped from a full-size anchor to a slimline anchor, then returned to production, still pumping at the KOP. The challenges with pump fillage when using full-size tubing anchors and the improvements in gas separation associated with the use of low-profile tubing anchors have been well documented in our industry and validated by the fluid level depression test. (McCoy et al., 2014). In May 2017, the tubing was pulled again, this time preemptively, and the BHA and pump were landed below the KOP at 60 degrees. Both workovers, occurring back-to-back, showed two separate and unique production increases, illustrating that landing the pump below the KOP had its own unique merit. This pump continued to operate until February 2024, when it was finally pulled due to excessive wear.

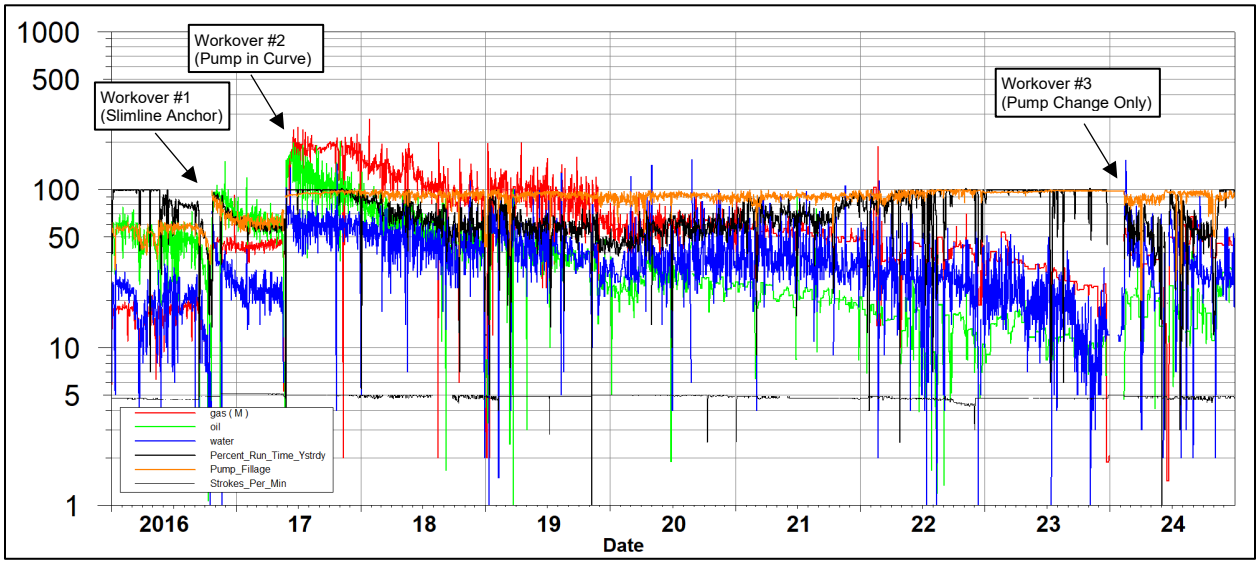

Figure 7. PRB Example Well #2

POWDER RIVER BASIN – HIGH-RATE EXAMPLE

Powder River Basin example well #3 is one of multiple examples that have sustained production rates of over 300 BFPD pumping from below the KOP for extended periods without failure. This well was converted from ESP to rod pump in August 2020, with a 2” RXBM insert pump landed at 59 degrees.

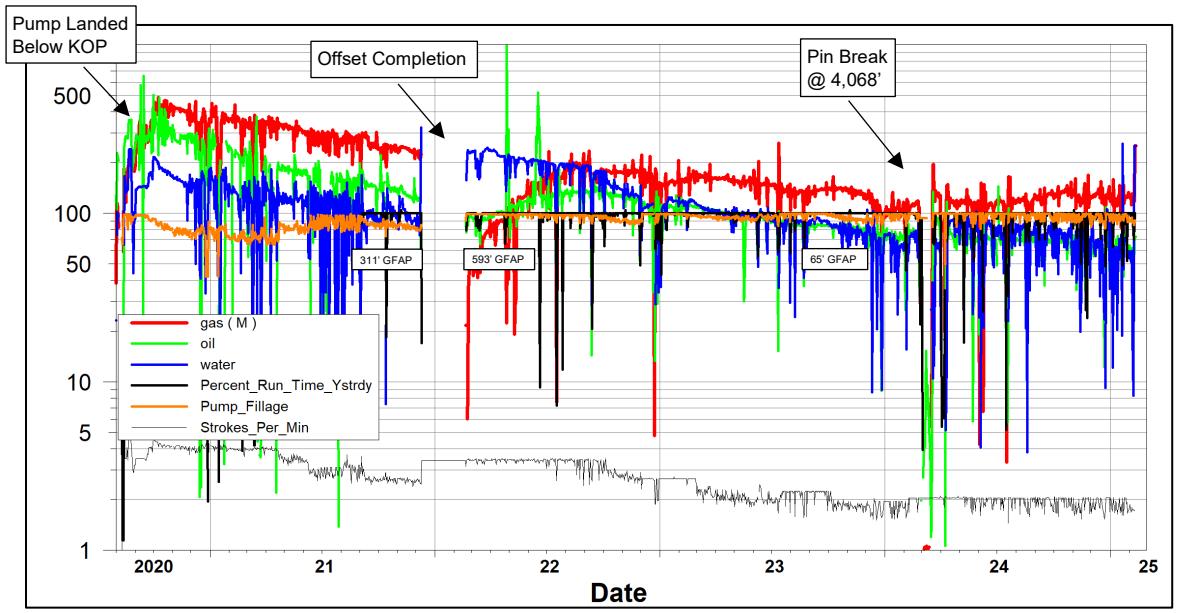

Figure 8. Powder River Basin Example Well #3

PRB ROD DESIGN (BELOW KOP)

Initially, 3/4” rods were used for service below KOP but were found to fail under compression too frequently. Testing with 1” rods resulted in too many holes in tubing. Ultimately, the guided 7/8” proved to be the most reliable for pumping through the inclinations and doglegs that exist below the KOP.

PRB ROD DESIGN (ABOVE KOP)

A mixture of 76, 77, 86, and 87 tapers have been used while pumping below the KOP. Design considerations had to carefully balance rod loading with the gearbox and structural limits of the available pumping unit. Initially, sinker bars at the KOP were employed but were found to cause too many holes in the tubing. Additionally, many 3/4” rods were failing in compression just above the sinker bar section.

This led to a transition away from using sinker bars in most designs. Instead, the 7/8” guided taper was extended, often several hundred feet above the KOP, replacing the

sinker bar section and large portions of the 3/4” taper. In some cases, the 3/4” rods were eliminated completely.
As of today, 214 wells in the Powder River Basin are being pumped below the KOP as the program has been largely successful. As shown in figure 9, 120 (53%) are 86 tapers, 64 (30%) are 87, and 30 (17%) are 76 and 77 tapers all with guided 7/8” through the curved section. Currently the average run time for these wells stands at 974 days.

It is important to note that most Powder River Basin wells in this study pump at or below 5 strokes per minute (SPM). The moderate to slow pumping speeds, long 7/8” guided tapers above and below the KOP, and tangents at 60 degrees are believed to be the reasons for the long run times achieved.

Rod Taper Breakdown – Currently Installed Rod Strings

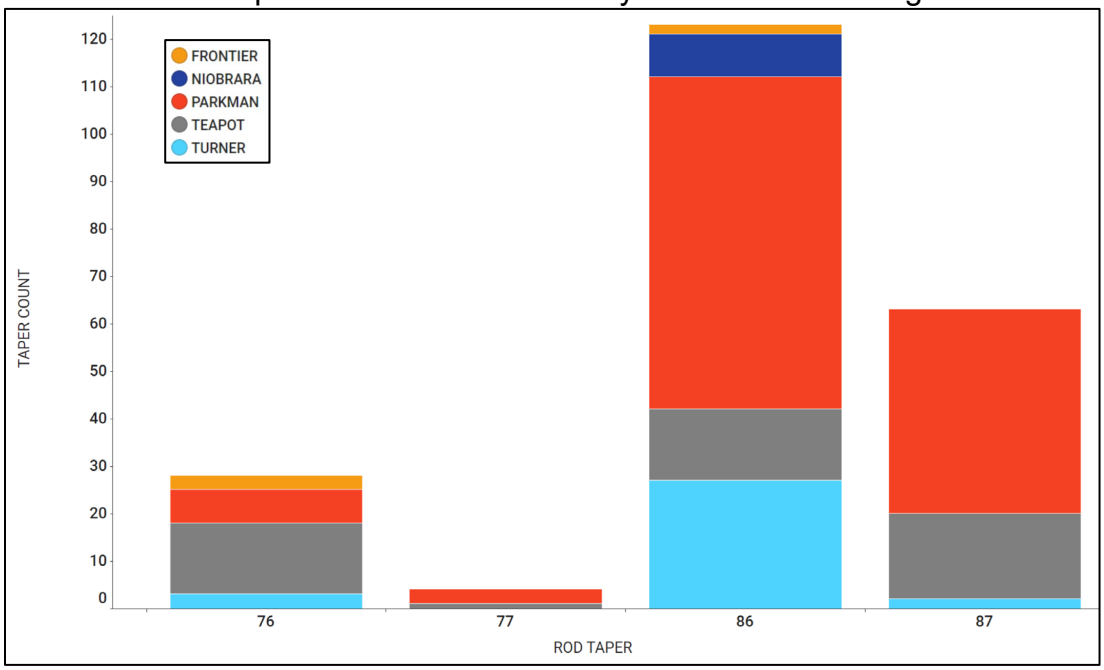

Figure 9. Rod Taper Distribution – Current Installs – Powder River Basin

PRB PUMP DESIGN

Initially, single API standing valve (SV) & single API traveling valve (TV) pumps with 3’ plungers were utilized to minimize pump friction, thereby reducing valve rod buckling and valve rod guide wear. Total pump clearance ranged from 0.004 to 0.008, depending on whether new or used components were employed. Spray metal valve rods, hard-lined valve rod guides, and API pattern titanium balls over tungsten carbide seats became the standard.

Recently, 4’ plungers with double API traveling valves have been adopted. The increased length of the plunger and double valving has not negatively impacted run time.

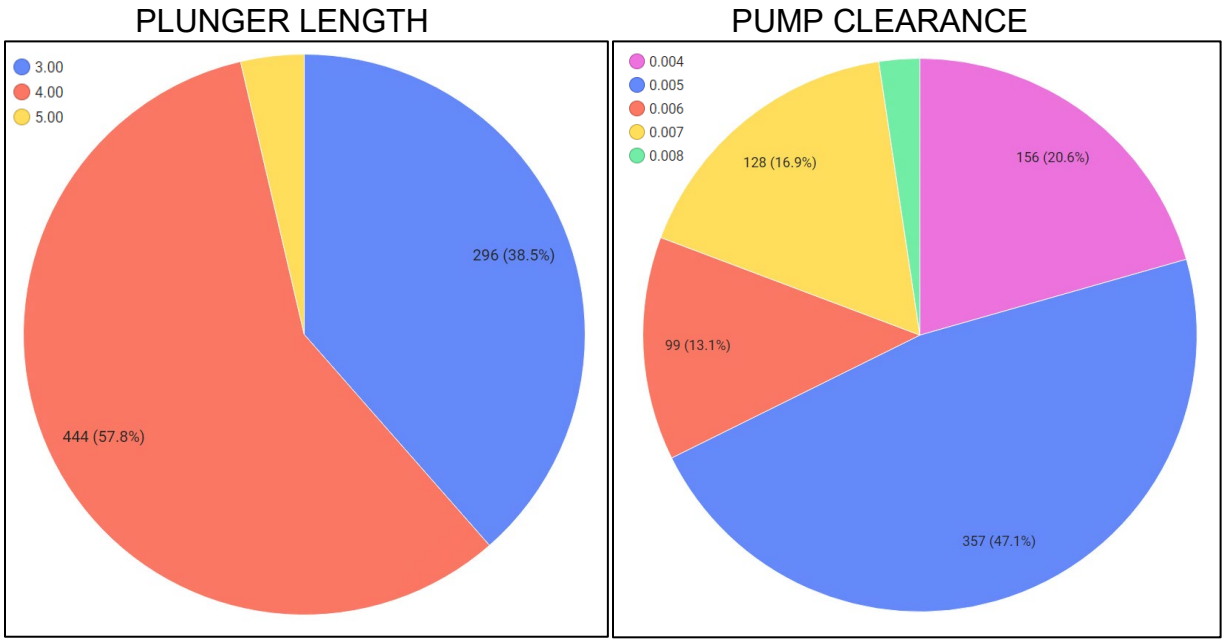

Figure 10. PRB Plunger Length & Pump Clearance– Historical and Current

The PRB is unique compared to other assets Devon operates in that only 50% of workover events result in tubing being pulled. There have been multiple instances of 2 or 3 pumps installed below KOP in the same tubing string over a 7-to-10-year period. For this reason, it is useful to analyze rod string run life and tubing string run life independently of each other. Below are plots of average daily fluid rates with the corresponding tubing string or rod string run time.

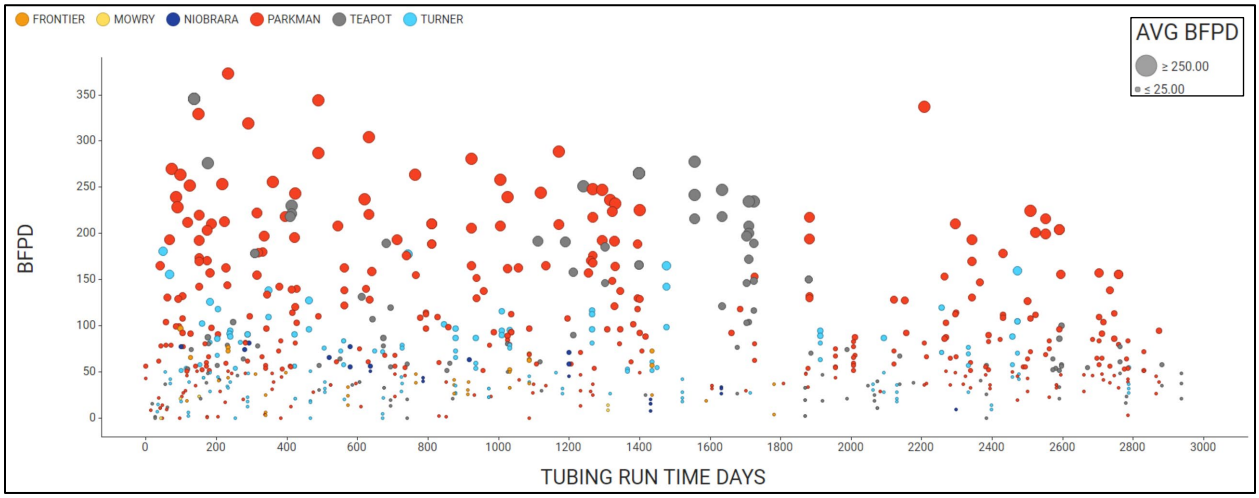

Figure 11. Average Fluid Rate (BFPD) vs Tubing String Run Time – Powder River Basin

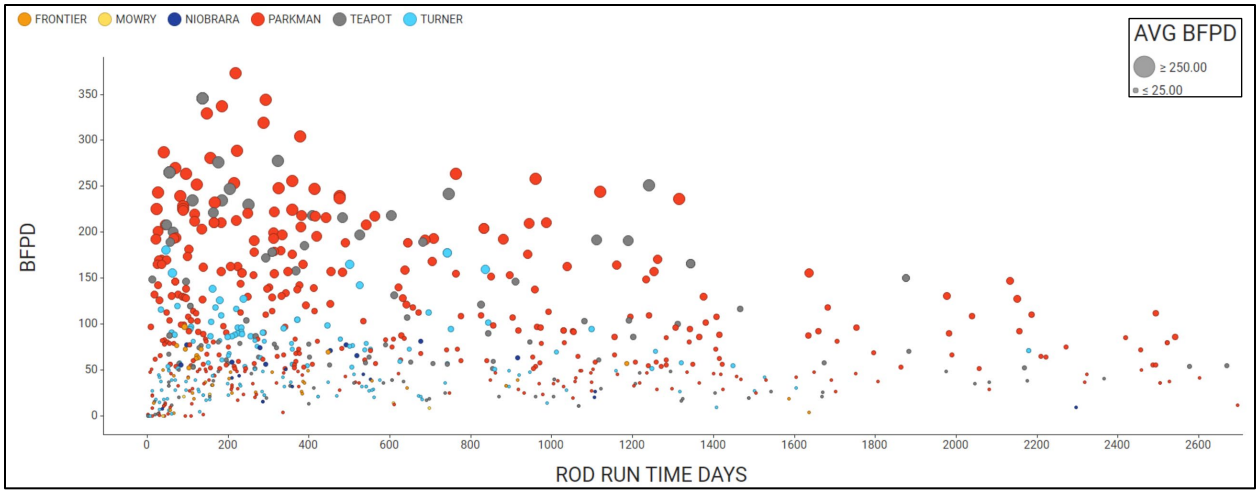

Figure 12. Average Fluid Rate (BFPD) vs Rod String Run Time – Powder River Basin

MISSISSIPPI LIME

Installations below KOP in the Mississippi Lime began in fall of 2014. This group of wells featured 300-foot tangents drilled at 70 degrees, originally intended for electric submersible pump (ESP) placement. Wellbore construction included a mix of (25%) 5.5-inch-long strings and (75%) 7-inch by 4.5-inch wells, with the 7-inch casing run to 90 degrees and the 4.5-inch liner set at the end of a 300-foot tangent at 70 degrees. Individual wells that were converted from ESP to rod pump at the KOP initially experienced low pump fillage.

The pivot to placing the pump below KOP upon conversion from ESP to rod pump was made promptly and wells continued to be pumped in the curve until the asset was sold 18 months later. A total of 33 wells were pumped below KOP, with multiple pumps running past the 500-day mark. Figure 13 below is an example of one such well.

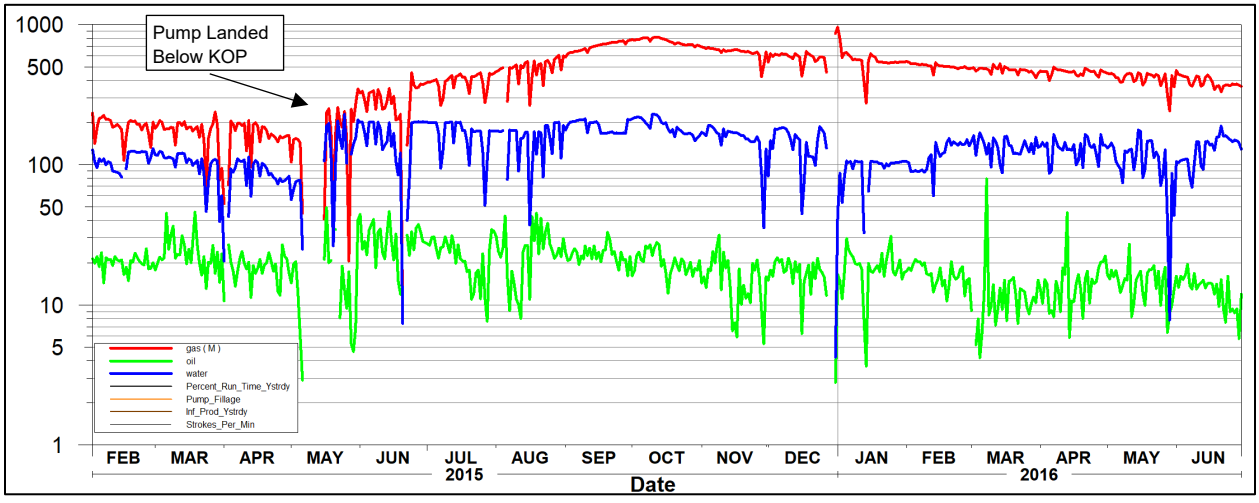

Figure 13. Mississippian Lime Example Well

DELAWARE BASIN

Pumping below the KOP in the Delaware Basin commenced in 2017 and by the end of 2019, more than 180 wells had pumps lowered into the curve. Unlike the preemptive lowering of wells in the Powder River Basin, Delaware Basin wells were lowered on an opportunity basis as they failed.

Wellbore Geometry: Delaware Basin wells were not drilled with pumping below KOP in mind and lack the tangents that are present in PRB wells. The absence of tangents complicated selection of a pump landing depth and often lead to aggressive pumping conditions. Pumps were landed as deep as 70°, in dogleg severities up to 15°, and guided 7/8" rods passed through doglegs of up to 23° in the curve. These extreme pumping conditions do not appear to be as detrimental to run time as initially expected, with many run times approaching 1-2 years in these conditions.

Design Evolution: The initial target area for pumping below KOP consisted of lower pressure, lower volume wells in the Northern portion of the basin, where some of Devon's first horizontal Bone Spring wells were drilled. The success of these installs led to increased pump lowering across the entire basin, including the deeper wells towards the Texas state line. These were, for the most part, higher pressure and higher rate pumping applications, requiring large bore insert pumps to match well inflow. The larger insert pumps and rates proved to be a challenging application, and many wells were returned to pumping at KOP after initial short runs below KOP.

Initially, insert pump specifications did not differ from the vertically landed pump specs of the time. The use of 5' plungers, double traveling valves, and HVRs were common. This was a contributing factor to short run times, especially in the higher rate wells, where valve rod wear was a common failure mechanism. Pump designs eventually settled on a 3' plunger with a solid spray metal valve rod and hard lined valve rod guide after HVRs repeatedly failed.

The evolution of the program back towards lower volume wells can be seen by comparing historical pump bore sizes and what is currently installed below KOP. Figures 14 and 15 illustrate that while 1 ¾" and 2" pumps were initially well-represented in the data set, the current program is now predominantly utilizing 1 ¼" and 1 ½" pumps. Notably, only four 1 ¾" pumps remain in use. The run life of the smaller pumps proved superior to the larger bore pumps with an average run time of 490 days for the 1 ¼" and 1 ½" and 370 days for the 1 ¾" and 2" pumps. Furthermore, the average run time for the 60 pumps operating below KOP at the time of writing this paper is 672 days and counting.

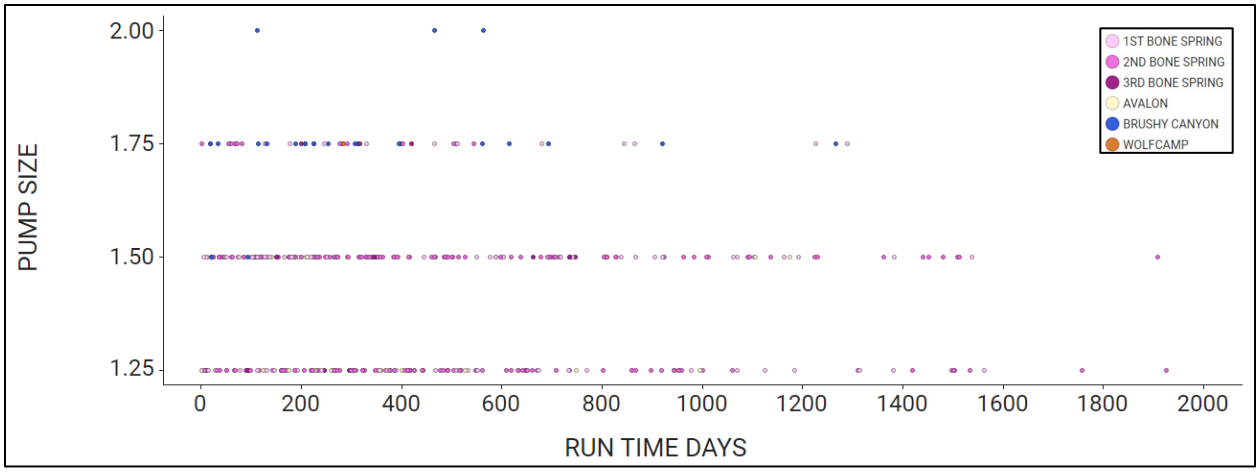

Figure 14. Delaware Basin Pump Size Distribution – Historical Installs

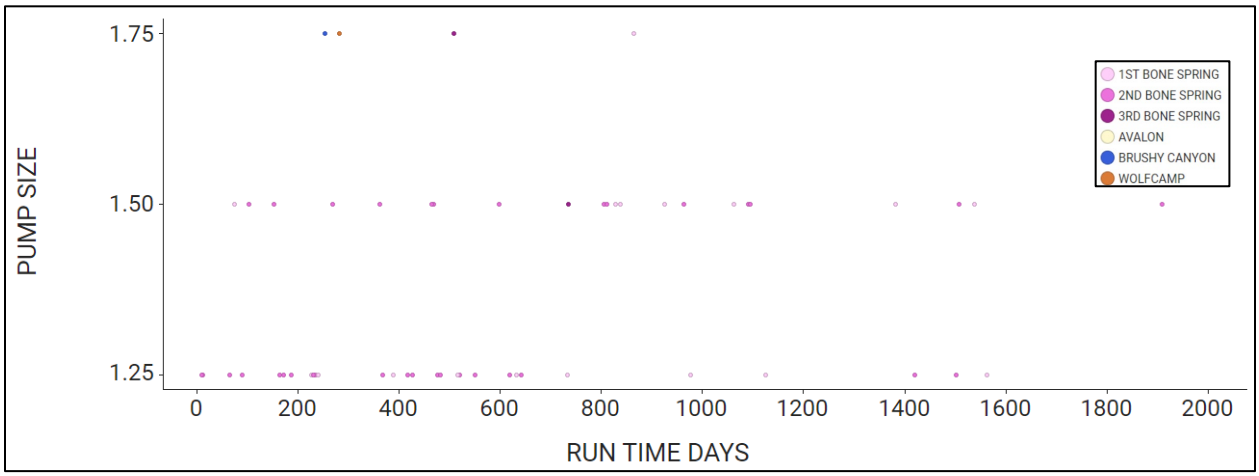

Figure 15. Delaware Basin Pump Size Distribution – Current Installs

Tubing Design: Most wells in the Delaware Basin have 5.5” long strings and as a result 2 7/8” tubing is utilized. Like the PRB, tubing anchors are set at KOP, followed by 25 to 30 joints of unanchored tubing, a poor boy separator, and mud joints.

Rod Design: Rod designs predominantly consisted of 1 ¼” fiberglass followed by 87 steel tapers. Some designs had ¾” tapers present but the ¾ rods were found to be a failure mechanism and most were eliminated over time. Approximately 20% of rod strings did not include fiberglass. Of the all-steel designs, 56% were 86 tapers and 44% were 87 tapers. Sinker bars were used at KOP in all designs, followed by guided 7/8” KD grade rods through the curve.

Failure Mechanisms: Pump failures due to wear, sticking, or parted valve rods were the predominant failure mechanism (68%), followed by holes in tubing, and rod parts.

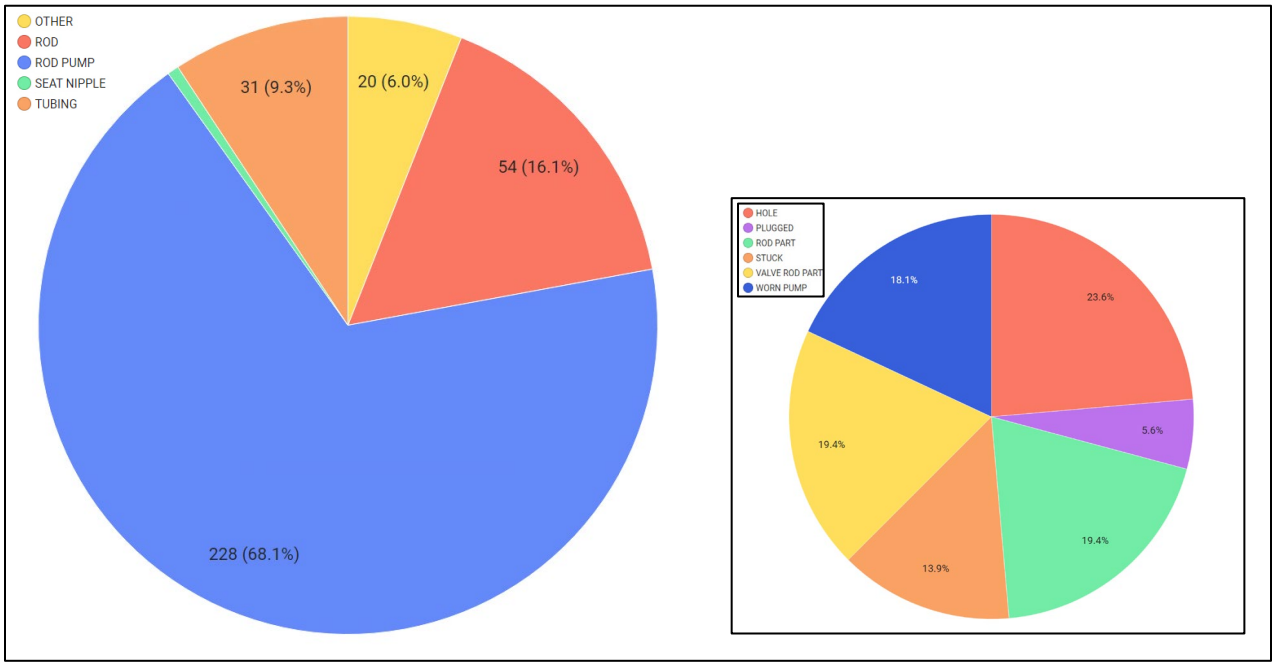

Figure 16. Failed Components and Failure Cause Comment – Delaware Basin

When comparing failed components in relation to failure depth and run time, failures predominantly occurred deep at the pump or near the surface. Wells with a run time exceeding three years almost invariably experienced pump failures. Failures at intermediate depths were primarily due to ¾" rod parts. These issues were mitigated by removing the ¾" taper either during the initial lowering or after the first failure. Shallow failures comprised a mix of parted rods and holes in the tubing. Holes in tubing were mostly above KOP and attributed to corrosion, which were unrelated to the lowering of the pump.

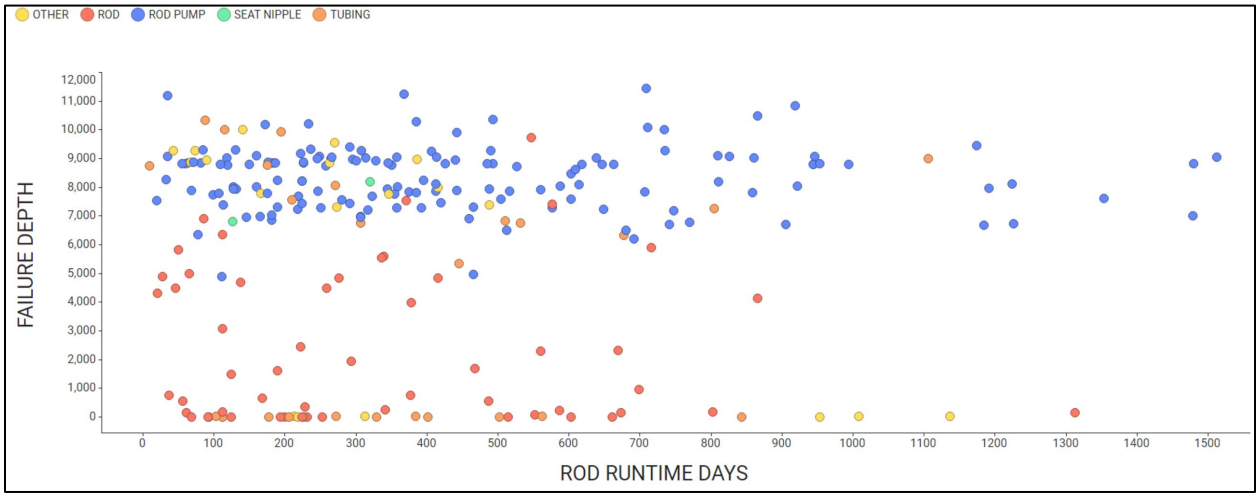

Figure 17. Failure Depth vs Run Time – Delaware Basin

Liquid production uplift was also short-lived compared to the PRB due to the lower permeability inherent to formations like the Bone Spring and Avalon. However, gas rates remained elevated compared to pumping at KOP. This, combined with the mechanical challenges listed above, resulted in two-thirds of these pumps being returned to vertical pumping. Of the 60 pumps that remain operating below the KOP, the most successful examples are wells producing less than 150 barrels of fluid per day (BFPD) and have similar pump build specs to the PRB wells.

Delaware example well #1 had a 3-year run pumping below KOP with a 1.25” RHBC and an 86 KD grade design with 1” sinker rods at KOP and guided 7/8” through the curve. Pump design utilized a .005 clearance 3’ plunger, initially moving 150 BFPD. The seat nipple was landed at 60° of inclination in a 9° dog leg.

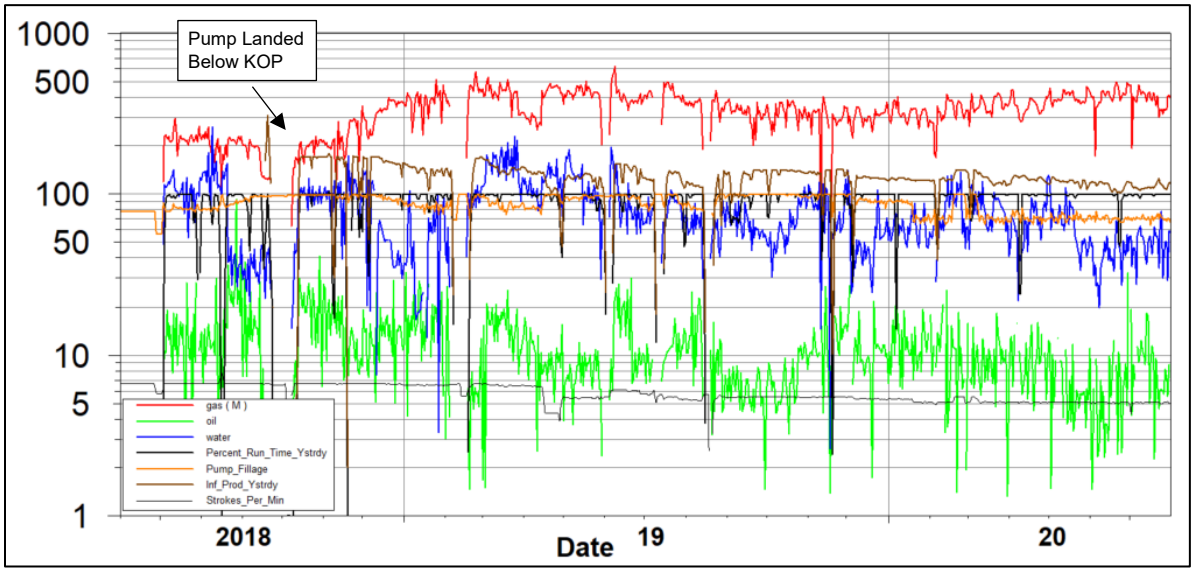

Figure 18. Delaware Basin Example Well #1

Delaware example well #2 had a 5-year run pumping below KOP. Rod design was an 86 KD grade taper using 1.5” K bars at KOP and 7/8” guided rods through the curve. Pump design utilized a 1.25” RHBC pump with a .006 clearance 3’ plunger, initially moving just over 100 BFPD. The seat nipple was landed at 63° inclination in a 7° dog leg. Several months after install, the well no longer needed 100% daily run time as the chart below shows, highlighting the ability to use idle time. After a 6-year run, the well was worked over when the tubing drain failed.

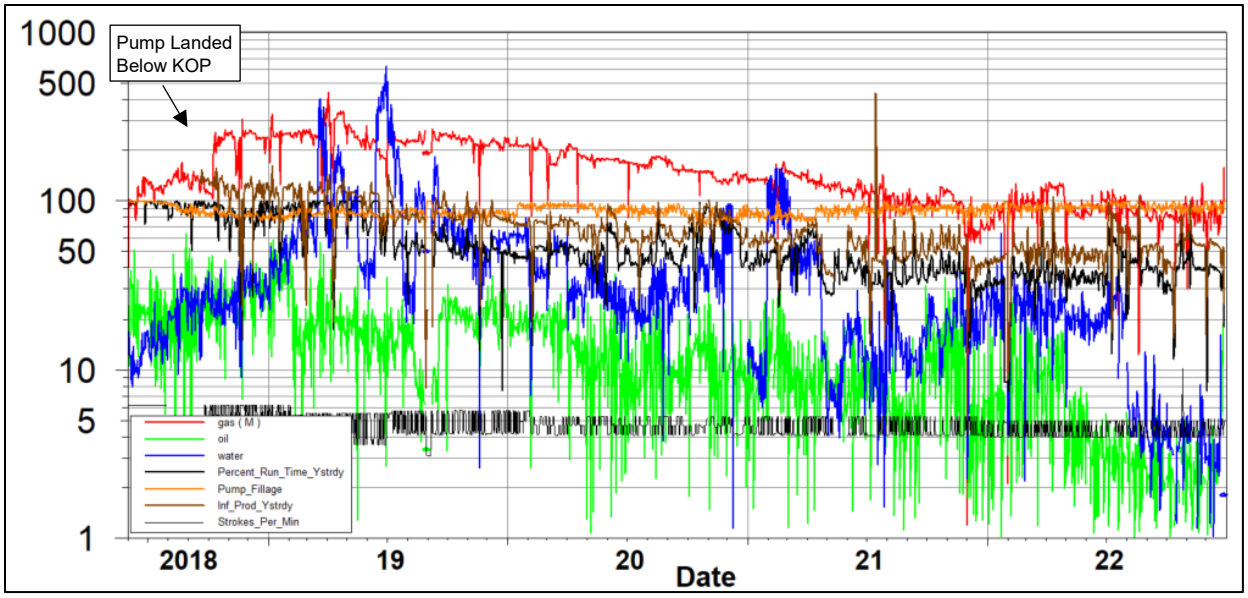

Figure 19. Delaware Basin Example Well #2

Delaware Basin example well #3 shows a high-rate example well producing below KOP from the Brushy Canyon formation. A 1.75” RHBC pump with a hollow valve rod and .005 clearance 6’ plunger was installed at 52° in a 6° dog leg. Rod design consisted of 1.25” fiberglass rods, an 87 steel taper, and 1 5/8” sinker rods at KOP followed by 7/8” guided rods through the curve. The initial design ran for a year until the polished rod parted. The pump was round tripped utilizing the same tubing string. This pump failed after only 2 months due to the significant traveling valve cage wear. One final attempt was made to pump below KOP, this time utilizing a 5’ plunger and slightly deeper seat nipple depth at 54°. The pump ran for 3 months and failed when the HVR parted at the connection to the top plunger cage. The pump was then returned to KOP.

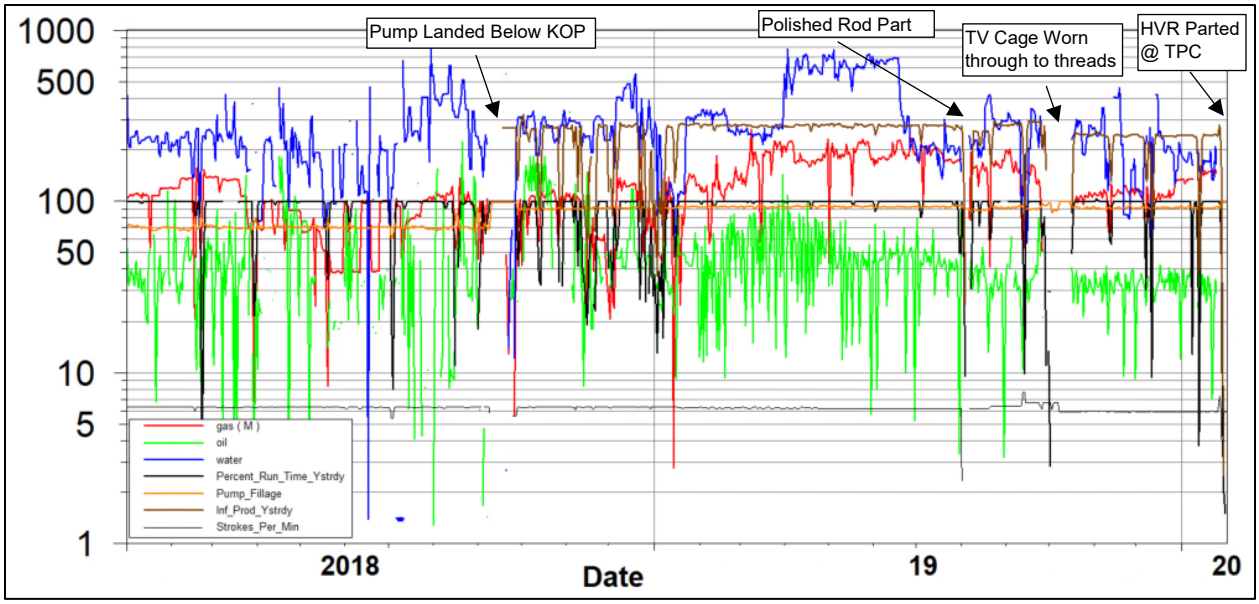

Figure 20. Delaware Basin Example Well #3

KEY LEARNINGS:

Visualizing installation timelines is essential for understanding the longevity of equipment in this dataset. For the 890 installations that have been pulled, the average run time for rod strings is 447 days, and for tubing strings, it is 708 days. There are numerous instances of exceptionally long runs, particularly in the Powder River Basin, that exceed these averages, as illustrated in Figures 21 and 22. The average run time for the 273 wells currently operating with below pumps the KOP is 857 days for rod strings and 1317 days for tubing strings. The contrast in run times with currently installed equipment vs pulled equipment underscores the design and well selection improvements that have been made over the past decade.

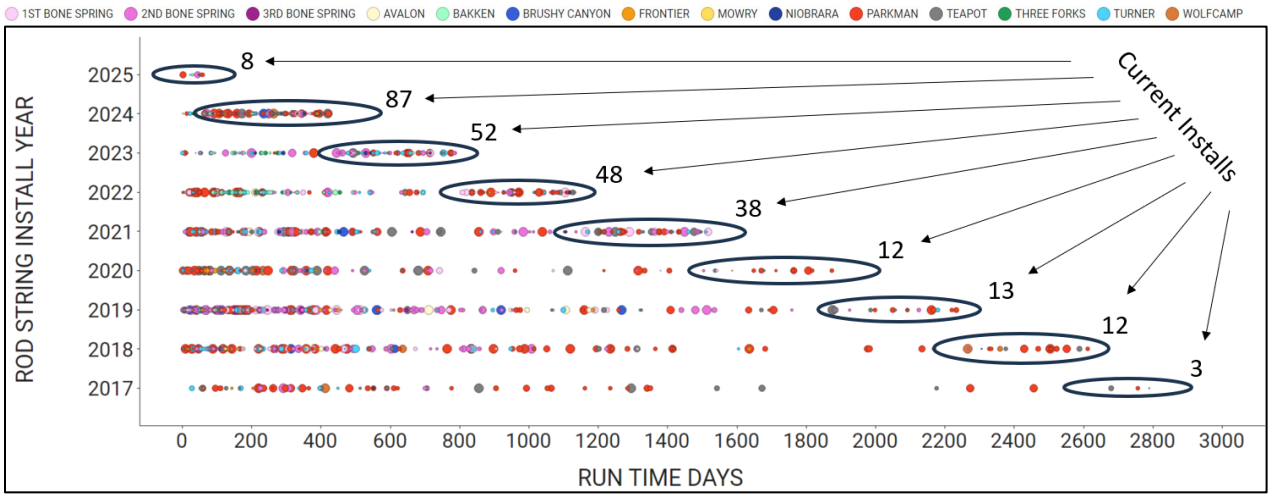

Figure 21. Rod String Run Time vs Install Year

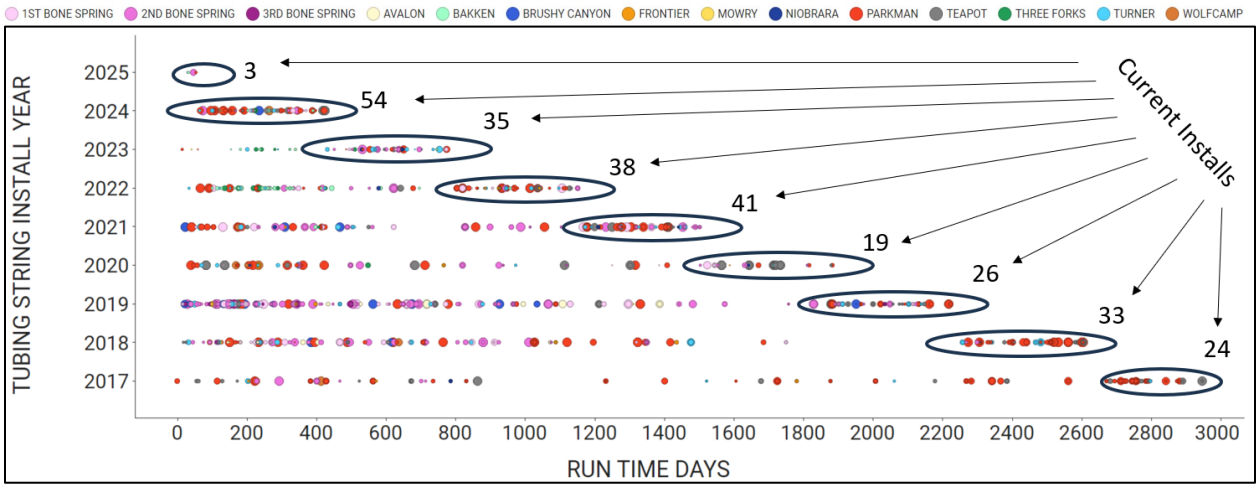

Figure 22. Tubing String Run Time vs. Install Year

Due to the size of this data set, installs were broken up into 3 categories based on run time: sub 6 months, 6 months to 2 years, and 2+ years. This was the best way to more clearly visualize failure mechanisms and success cases for short and long runs.

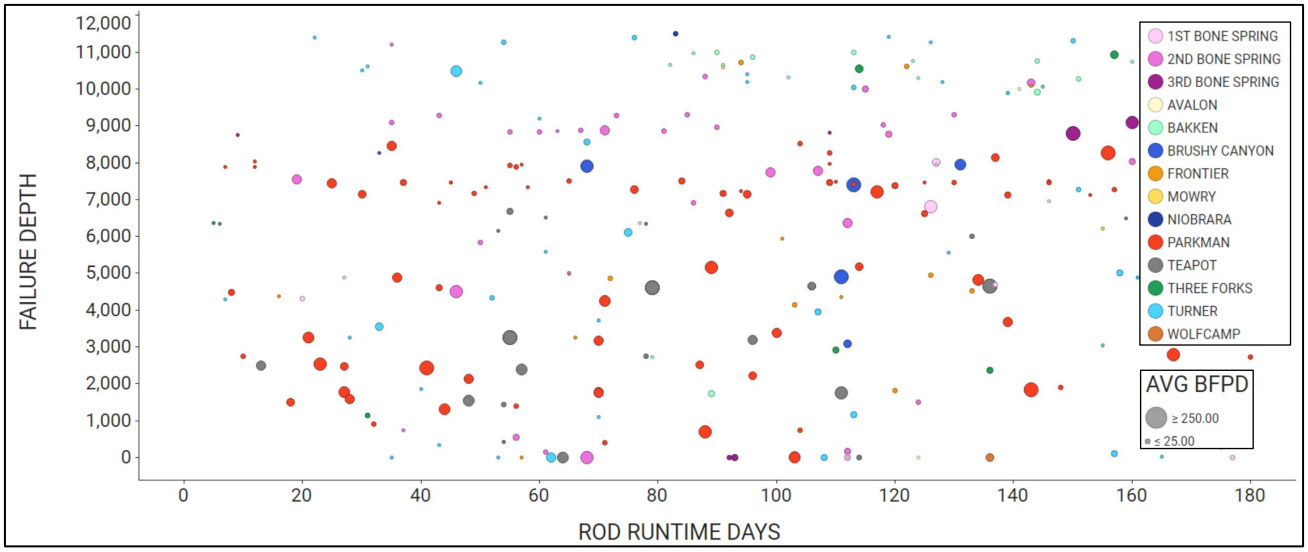

Figure 23. Failure Depth vs. Run Time – Sub 6 Month Runs

Failure depths for sub 6 months runs were evenly distributed between surface and KOP. Strong correlation between Delaware Basin wells and failures at pump depth due to HVR usage and operational challenges mentioned previously.

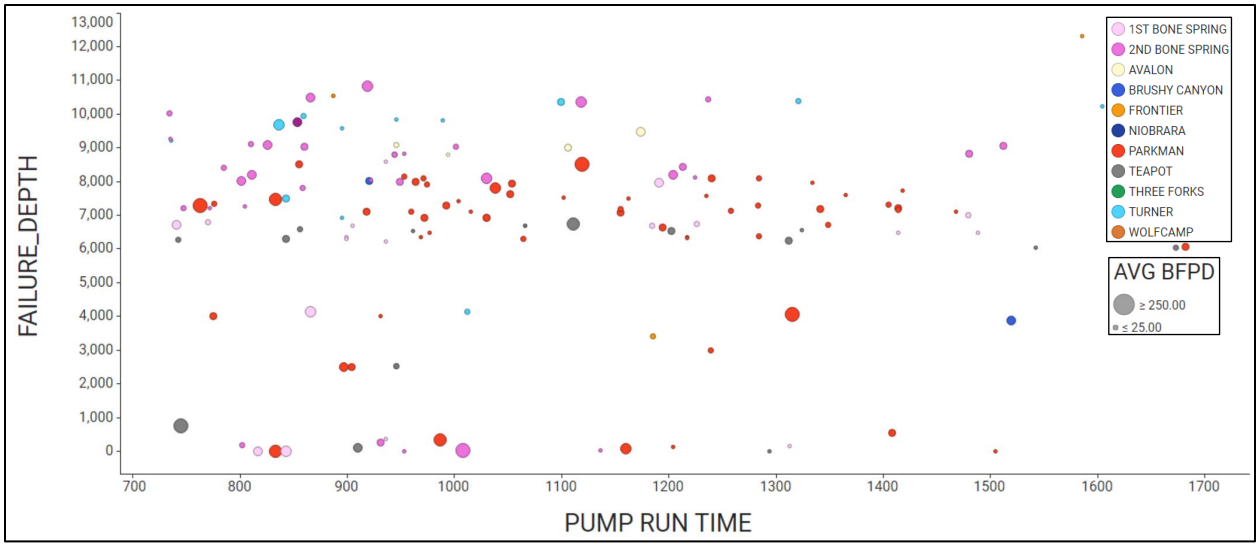

Figure 24. Failure Depth vs. Run Time – 2+ Year Runs

Failure depth distribution for 2+ year runs are concentrated at or near the pump depth in the 154 instances shown on the above chart. It is important to point out there are currently over 184 pumps running below KOP for 2+ years that have yet to contribute to this data set in Figure 24.

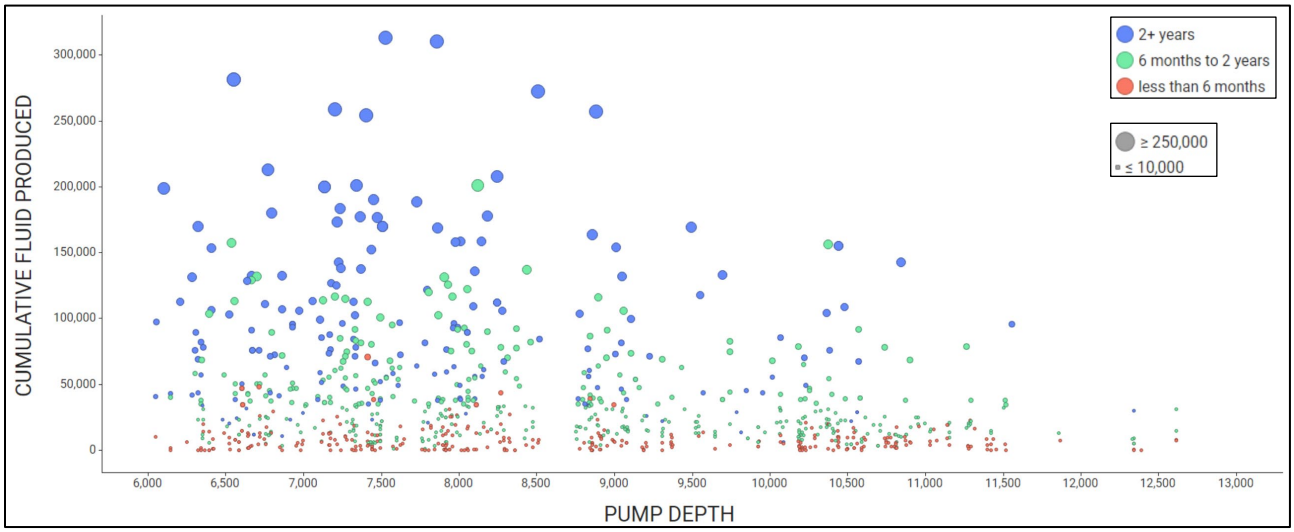

Figure 25. Cumulative Total Fluid Produced vs. Pump Depth

Figure 25 shows that longer runs and larger cumulative fluid volumes produced per pump install have been predominantly achieved in shallower wells, some of which have more conventional inflow characteristics. Deeper wells typically produce from higher pressure / lower PI formations, making pumping below the KOP more appealing for late life, low volume wells.

RECOMMENDED PRACTICES:

1. **Tangents Below KOP:** 150’ tangents between 60 and 70 degrees of inclination create the most desirable condition for pump placement below KOP. This requires planning with drilling years in advance of rod pumping, which is often not an easy concept to sell. However, the incremental cost of doing this is often negligible in terms of rig time and additional casing required.

   If a tangent cannot be found, the lowest dogleg severity stretch of the curve can be adapted for the same purpose. It is important to understand that this approach is not without risk to equipment longevity and should be limited to wells making under 150 BFPD. It can also be useful to look at drilling reports to understand exactly where rotation and slides were taking place, to identify a favorable spot to land a pump.

   Operators using 7” casing by 4.5” casing designs should investigate the possibility of landing the liner hanger at the end of the tangent, so that slimhole equipment can be avoided.

2. **Tubing Design:** Tubing should be anchored at the KOP using a full drift ID tubing anchor. A full drift ID is necessary to maintain a continuous long taper of 7/8” rods with full size couplings and guides both below and above the KOP. In 7” x 4.5” liner wells with the liner top at KOP, it is necessary to cross over to 2 3/8” tubing before transitioning into the 4.5” liner. A standard poor boy desander combo or slotted joint can be used for gas separation with 2 3/8 or 2 7/8 mud joints.

3. **Rod Design:** Above KOP, designs can consist of virtually every type of taper combination depending on engineering needs and existing equipment available. Sinker bars can be used above KOP but the extended 7/8” taper design mentioned below can be used instead, depending on bottom minimum stress requirements.

   Below KOP, the KD grade 7/8” rod (8 GPR) has proven to be a reliable performer for pumping through the inclination and doglegs that exist below the KOP. The 7/8” taper in the curve can be extended above KOP in many cases, eliminating all or as much of the ¾ section as possible or as needed. In fact, this design without sinker bars has yielded some of the longest run times in our data set.

   In wells with 4.5” casing at KOP, it is important to transition to 2” guides and slimhole couplings before entering the 2 3/8” tubing. While this may seem obvious, it is nonetheless important to keep in mind while designing.

4. **Pump Design:** When designing pumps for service below the KOP it is important to consider the potential for valve rod buckling. To mitigate this problem, it is recommended to run a solid spray metal valve rod with a hard lined valve rod guide. Hard lining is achieved using a tungsten carbide or stellite insert in the top of the valve rod guide. This combination will greatly decrease valve rod, valve rod guide,

pump extension, and even pump barrel wear and therefore prolonging pump life at high inclination.

Most applications can use a 7/8” spray metal valve rod with a collet or deep bore connection at the top plunger coupling. For the valve rod bushing, a collet connection is recommended. 1 1/16” spray metal valve rods have also been utilized below KOP with some 1.75” and all 2” pumps. Hollow valve rods are not recommended for service below KOP due to their rigidity and the fact that the corresponding valve rod guide is not hard lined.

A shorter plunger with a single TV cage can reduce pump friction and subsequently valve rod buckling, especially in wells without tangents. In wells with tangents, extending the plunger length and double valving has not shown to be detrimental but is not always necessary depending on well conditions.

Both cup style and mechanical hold downs have been successfully used below KOP although mechanical is the most common in this data set.

5. **Well Selection:** Choosing to pump below the KOP is predicated on 2 factors: wellbore geometry and total liquid rate needing to be produced. Pumping below KOP with a pre-planned 150’+ tangent section between 60° to 70° degrees of inclination with less than 1° DLS is the most desirable scenario.

   Pumping below KOP without a tangent is possible. However, the likelihood of being able to lift volumes exceeding 150 BFPD without a tangent and still achieve acceptable run times has shown to be very low. Designers must aim to land the pump in the lowest DLS stretch of the curve, which usually results in pumps being landed anywhere from 50° to 70° degrees of inclination. It is also useful to examine how the curve was drilled to understand exactly where rotation and slides were taking place. Straight spots below KOP suitable for pump landing can usually be found in long stretches where rotation was taking place during drilling.

SUMMARY

While pumping below the KOP is not a one-size-fits-all application, it is likely to play a greater role in the future as the number of horizontal rod pumped wells continues to grow. Successfully pumping below the KOP requires careful consideration of multiple variables. Well selection, pump placement, tailored equipment designs, and operating parameters all influence successful outcomes.

Operators are particularly encouraged to investigate the feasibility of incorporating tangents into their well designs. This simple yet impactful feature could make pumping

below the KOP a more effective strategy in the years to come, unlocking greater production potential while extending equipment run life.

REFERENCES

James N. McCoy, O. Lynn Rowlan, Carrie A. Taylor, A.L. Podio "Tubing Anchors Can Restrict Production Rates and Pump Fillage" URTeC: 1918491, Denver Colorado, USA, 2014.