MAXIMIZING PRODUCTION EFFICIENCY IN BEAM PUMP WELLS USING ROD GUIDE DESIGN OPTIMIZATION

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ABSTRACT

There are many challenges associated with sucker rod lift in deviated wellbores that can lead to high failure rates and lost production. Tubing failures are amongst the costliest workovers and are often a result of metal to metal contact between the rod coupling and the tubing.

Evaluating tubing on-site using both gamma and electromagnetic inspection (EMI) allows for proper design optimization before returning to production. The tubing scan can be aligned with deviation data, previous rod design, and failure history to adjust the string design to effectively extend mean time between failures (MTBF) and improve asset value.

An effective rod guide strategy was developed to mitigate tubing wear using proper guide type, material, and placement. The implementation of this strategy has helped to maximize production efficiency across the asset.

INTRODUCTION

NOV Tuboscope partners with a key exploration and production company with over 700 rod pump wells in the Eagle Ford Shale located in South Texas. This operator chose sucker rod pumps (SRP) to produce this area because it is one of the methods of artificial lift that can produce the well as the reservoir pressure declines and the production rate decreases. SRP are a well-known technology, which is reliable, versatile, and has reasonable operating expense. The challenges of producing the Eagle Ford wells include paraffin, corrosion, solids, deviated wellbores, slug flow and foamy gassy fluid.

This paper will discuss the success of an ongoing optimization program established in 2016 to help mitigate the coupling and tubing wear issues that occur due to deviated well bores. This strategy includes using equipment that identifies tubing condition at the wellhead with contact EMI and gamma inspection, to accurately determine tubing defects and where they occur. Following the tubing inspection, a proprietary rod guide software is used to adjust the rod design prior to returning the well to production. Following the subsequent failure, the rods and tubing are reevaluated to determine the performance of the design ran during the previous workover and if any further changes are needed to meet the four-year run life target.

Tubing Inspection

Prior to 2015, different wellhead inspection equipment was evaluated. Non-contact EMI only wellhead inspection equipment was compared to another inspection unit that incorporates contact EMI with gamma inspection. Gamma technology is used for in-plant tubing inspection to measure the wall thickness of the tubing. When using gamma on-site, longitudinal defects such as rod wear, are more accurately identified. EMI measures flaws in the tubing body in the transverse plane, such as pitting. It was determined that contact EMI was better at detecting anomalies in the tubing because the signal is strongest at the surface of the joint. Further, when gamma is used in conjunction with contact EMI, the accuracy of the tubing inspection is far better than the non-contact EMI only inspection equipment previously used. For this reason, EMI with gamma wellhead inspection equipment has been exclusively used whenever tubing is pulled following 2015. This equipment consistently detected tubing wear that corresponded to the visual inspection of coupling and shoulder wear on the rods prior to pulling tubing. Tubing is classified following API RP 5C1, *Recommended Practice for Care and Use of Casing and Tubing,* according to the loss of nominal wall thickness and furthermore that the thickness is specified with a standardized color-coding system (see Table 1). Tubing with wall loss greater than 30% is removed from the well and replaced with new or yellow band tubing. Wellhead inspection allows for sequential tubing condition that provides vital information for making real time design changes at the time of failure.

Rod Guides

It was identified that injection molded rod guides are an effective method to mitigate wear on tubing from metal to metal contact and this paper will provide evidence to support that case. The polyphthalamide (PPA) glass filled and polyphenylene sulfide (PPS) glass filled materials initially used in the Eagle Ford resulted in material failures and ultimately tubing failures from lack of protection. Because of these issues, a proprietary modified PPS guide material was standardized beginning in 2016.

Erodible wear volume (EWV) is a crucial component to the effectiveness of a rod guide (see Figure 1). EWV is the amount of guide material available to wear before the coupling contacts the tubing and will vary based on the length of the guide or shape of the vanes on the guide. Coupling size also impacts the effective EWV of a rod guide because larger couplings reduce the amount of stand-off between the coupling and tubing. Therefore, one-inch rods often require more guides per rod to prevent coupling contact with the tubing and normalize wear patterns long term in the well compared to the other rod sizes (see Figure 2). The standardization of a rod guide design offering high EWV with a straight vane and tapered ends to improve flow efficiency was implemented throughout the field in 2016 to maximize performance.

Along with the standardization of rod guide material and rod guide design, guides per rod were restricted to three configurations, 4, 6, and 8 per, to simplify inventory and streamline logistics. The guides are spaced strategically on the rod, approximately 12 to 16 inches from the pin end to minimize coupling movement and allow space for proper rod handling. When higher levels of deviation and tubing wear justify 6 and 8 per guide spacing, doubling of the rod guides near the coupling is used to further minimize coupling movement and improve hydraulic efficiency (see Figure 3). This also allows for improved flexibility compared to evenly spaced rod guides of similar quantities.

Rod Guide Software

The proprietary rod guide design software incorporates rules built on empirical data to help extend mean time between failures. Beginning in 2016, it became standard practice to scan tubing anytime it was pulled and use the software to help generate an optimized string design. The tubing scan is plotted alongside the dog-leg severity (DLS), inclination angle, side loading, failure history, and corresponding rod string design to recommend guide design, material, guides per rod, and depth placement based on a target run life (see Figure 4). It also became standard practice in 2016 to use this program to proactively design the rod string upon initial install to mitigate tubing wear based on the deviation and well conditions.

EVALUATION

Before implementing the standard practices outlined above, PPA filled guide material and smaller guide designs offering less EWV were used. This resulted in an increase in rod and tubing wear related failures occurring earlier than the desired four-year target run time. During these workovers, higher quantities of rods and tubing required replacement due to wear. The wells considered in this analysis included any well scanned following January 2016 to establish a baseline for material conditions and performance prior to the optimized design installation. When a subsequent tubing pull occurred, tubing was scanned, and the effectiveness of the optimization program could be evaluated. The tubing scan from the first pull and the second pull can be plotted side by side to visualize the impact design changes have made on the tubing condition (see Figure 5).

During this time frame, 50 wells have experienced at least a second tubing pull for consideration. The average tubing run time of these wells prior to the first pull was 529 days. Out of these 50 wells, half of them showed an improvement in tubing run time between pulls. The 25 wells that saw an increase in run time improved by an average of 78%. The other half of the wells that did not exceed the previous run time were pulled for a variety of reasons including pump failures, rod parts, tubing splits, and proactive pulls for offset frac activity. Only 10 of the 25 wells that didn’t exceed previous run time were related to wear on the rods or tubing. All of these failures occurred in rods that were reran from the previous pull. It is likely that rods were not accurately identified during the previous pull and rod guides that were no longer offering wear protection were used. It is difficult to visually evaluate the remaining EWV respective to the coupling size. This demonstrates the limitations to visually inspecting rods at the rig site while pulling but still offers an effective way to make real time decisions for optimization when compared to the tubing scan.

When rods were pulled prior to the tubing scan, any rods visually exhibiting wear in the shoulder or rod guide were laid down. There was a 60% average reduction in rods that were laid down for all 50 wells considered, improving from a 193 rod average the first pull, down to a 76 rod average the second pull. Even the 25 wells that saw an increase in run time, showed almost a 50% reduction in rods that were no longer viable. The increased rod guide performance seen in the rod string recovery directly correlates to the tubing condition at the time of the second pull. An average increase of 10% yellow band tubing was recovered on the second pull across all 50 wells. The green and red band tubing joints that get laid down also saw a 5% and 2% decline respectively. Even the 25 wells that achieved run time improvement followed in line with these averages. Increased material recovery will directly impact the cost associated with workovers over the life of the well and help contribute to extended operation.

CONCLUSIONS

It has taken several years to implement the optimization program now in place and it continues to improve as wells are worked over. The effective use of on-site tubing inspection incorporating both gamma and contact EMI technologies allow for thorough defect detection. When this data is aligned with the deviation survey, previous rod string, and failure history in the rod guide software, wear related failures can be correlated to depth and cause throughout the well bore. This rod guide strategy specific to the well conditions that targets these areas with improved guide design and material has been a key factor in reducing wear related failures across the field.

There were 50 wells that experienced two tubing pulls since the implementation of this rod guide optimization program. Even with an average first run of 529 days, 25 wells saw an average 78% improvement in run time prior to the second tubing pull. Out of the other 25 wells that did not increase run time, only 10 of these tubing pulls were wear related and all of these failures occurred in a section of the well where rods were reran from the previous pull. These wells help capture the success of the program despite the time frame being more conducive for shorter run times between tubing pulls. There are many more wells not considered that have only one tubing pull and have surpassed the previous run time. For this reason, the overall failure rate and MTBF for the asset help capture the impact of this strategy.

The optimization strategy outlined above has lowered the failure rate across the field by 49% since it’s induction. This is a direct result of reduced tubing failures and rod failures (see Figure 6). Coupling wear failures are the main cause of rod failures in this field and their decline can also be partially attributed to the rod guide strategy. During this time frame, tubing failures alone have dropped by nearly 90% because of proper guide material, design, and placement. Additionally, rod related failures have decreased by 40%. The reduction in failures across the asset has led to a 67% improvement in MTBF. This program has proven to be a critical piece in reducing failure frequency across key components of the rod system.

REFERENCES

1. American Petroleum Institute. (1999). API RP 5C1, Recommended Practice for Care and Use of Casing and Tubing. Washington DC: American Petroleum Institute.

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TABLES & FIGURES

Table 1 – API RP 5C1 Tubing Thickness Color Coding

COLOR	MINIMUM WALL LOSS (%)	MAXIMUM WALL LOSS (%)
Yellow	0	15
Blue	16	30
Green	31	50
Red	51	100

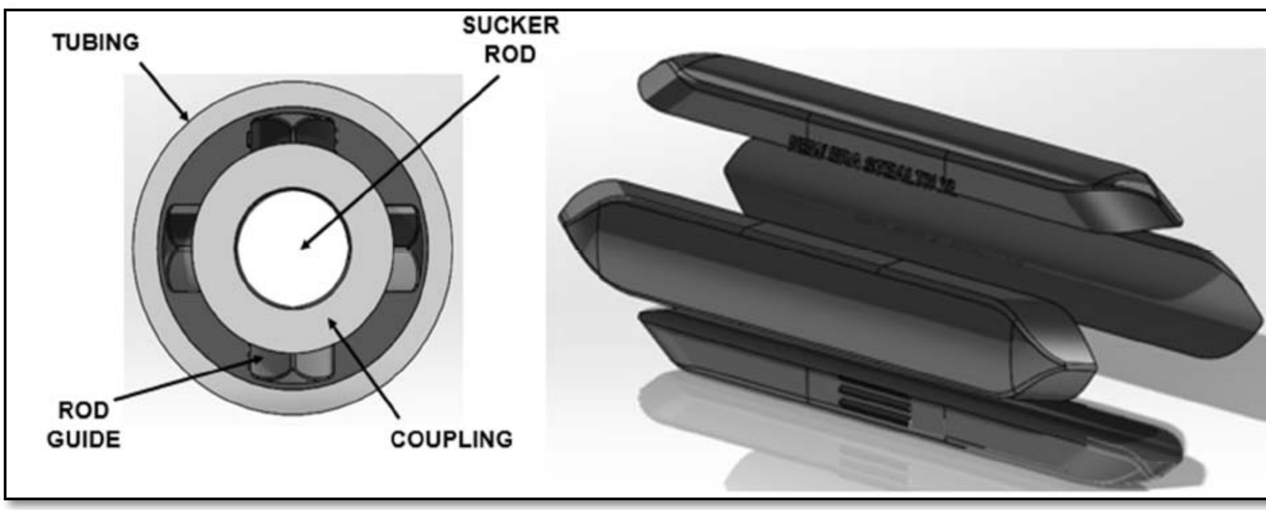

Figure 1 – Erodible wear volume of rod guides in tubing

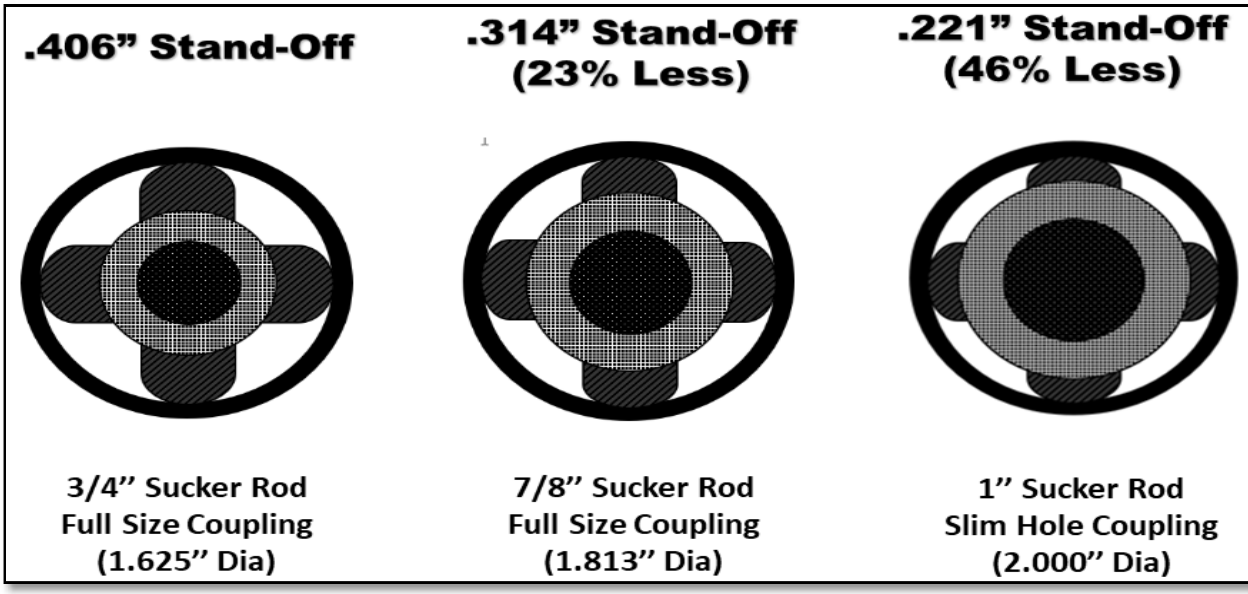

Figure 2 – Erodible wear volume and stand-off with respect to rod size

Figure 3 – Rod guide spacing

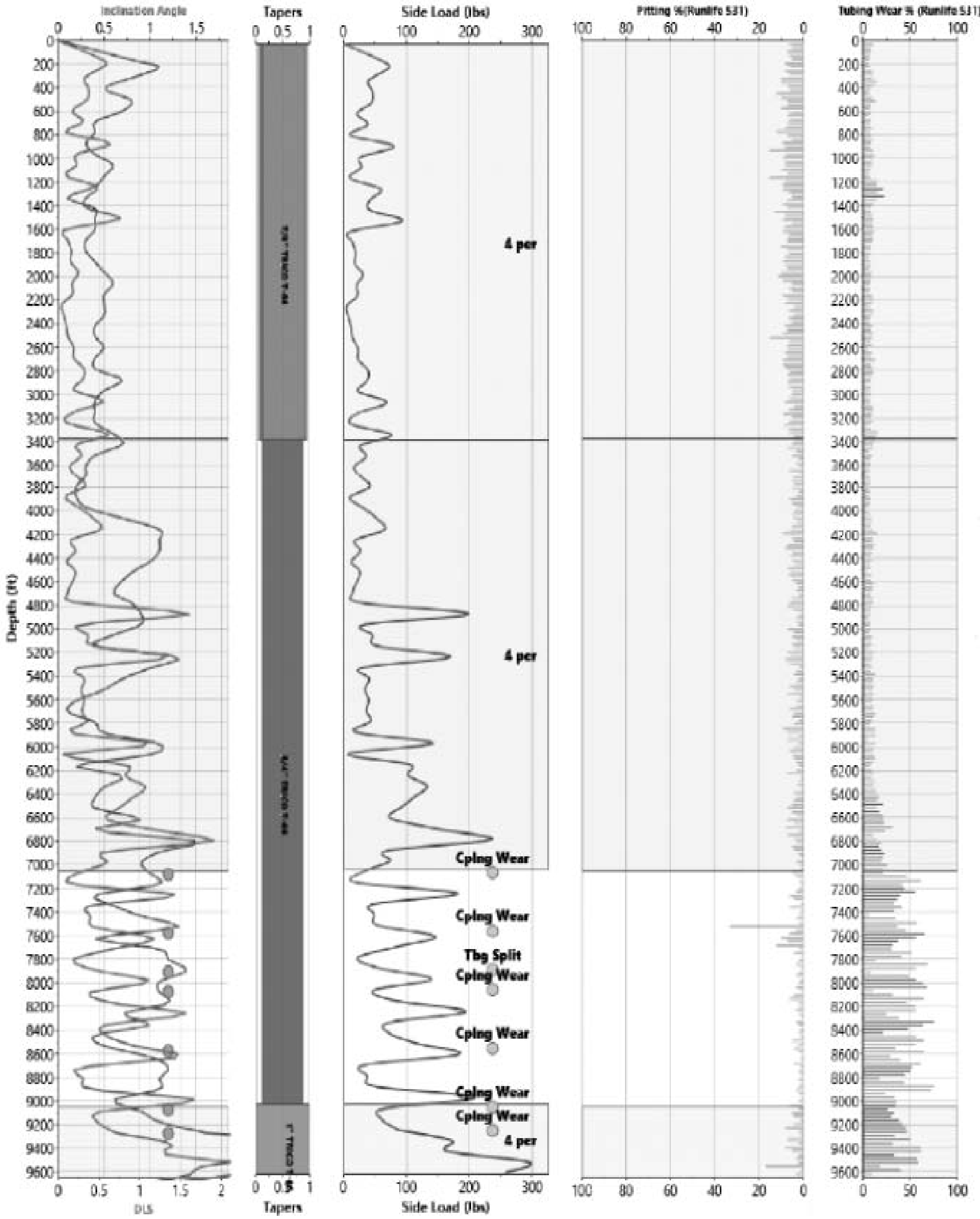

Figure 4 – Rod guide software well example (Well A)

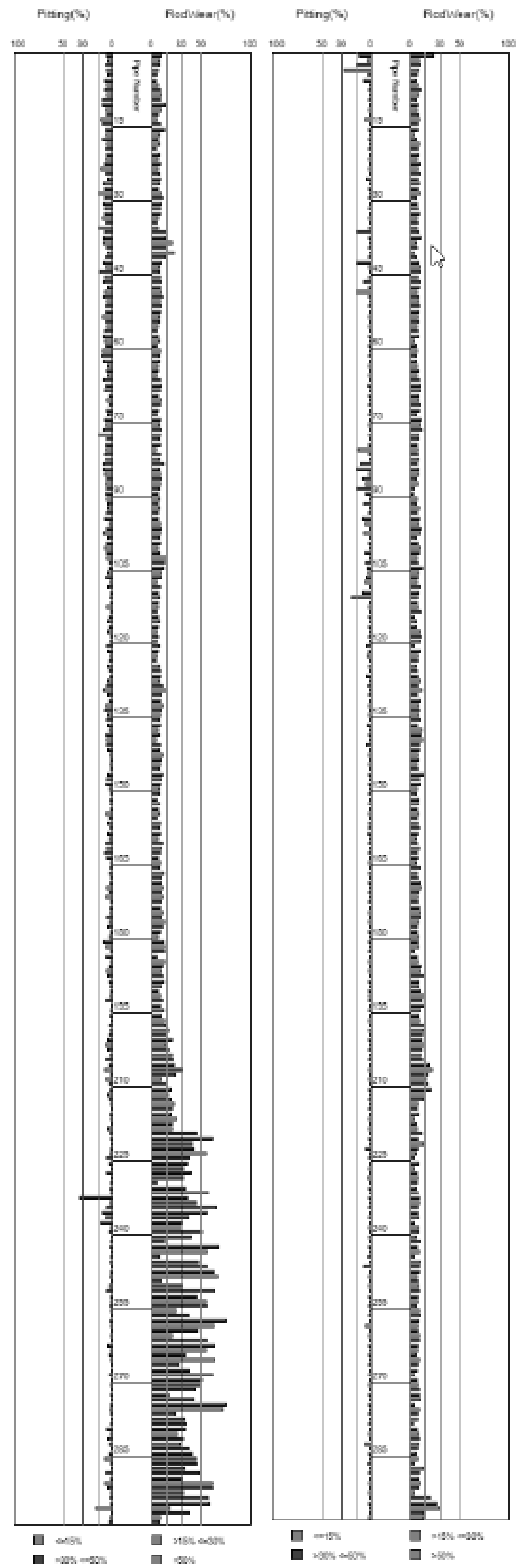

Figure 5 – Tubing scan comparison example (Well A)

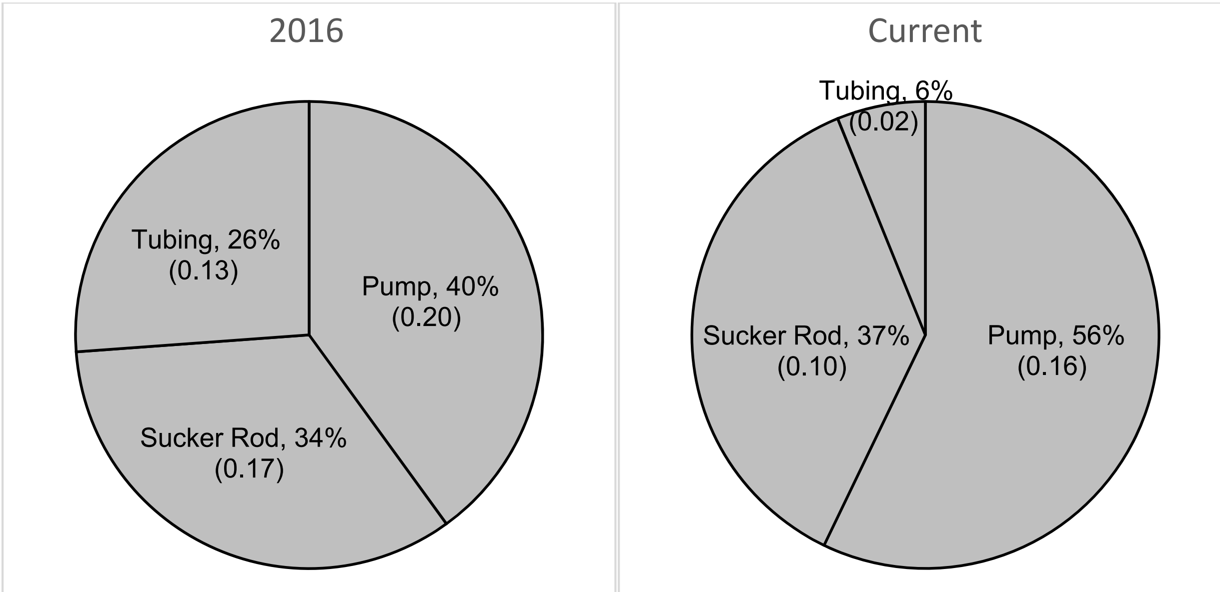

Figure 6 – Failure distribution by mechanism