PREVENTING FAILURES FROM THE POLISHED ROD CLAMP TO THE DIP TUBE

Rodney Sands
Dover ALS/Harbison-Fischer

ABSTRACT
This paper will discuss reducing failures in rod pumped wells by using best practices and design changes. The theme of the paper is to share solutions observed over the last 41 years while working with rod pumped wells. These best practices applied from the polished rod through the bottom-hole assembly have been proven to improve run time between failures. The topics discussed are improper installation of equipment along with the effect of a properly designed bottom-hole assembly. I will also highlight pump designs and accessory items to help with sand and gas issues. When you lower your failure frequency, you are reducing exposure to potential accidents benefitting us all.

INTRODUCTION
Sucker Rod Pumps are the most popular artificial lift method in the world. Some of the reasons are their toughness, ease of automation, energy efficiency, and having the highest drawdown capability. It is not uncommon for a rod pumped well to have a 5 to 10 year run life when properly designed and operated. When best practices are not used, it also can reduce that run time to just a few months. Many operators measure their success by taking the number of well failures divided by the number of rod pumped wells in a 12-month period.

BACKGROUND
Many rod lift failures are brought to the forefront during well failure review meetings. In these meetings the root cause of the failures will be determined and future best practices planned to reduce the overall failure frequency of the producer's wells. Typically, operators consider a high failed well one that fails two or more times in a 12-month period. I have observed when we first focus on the high failed wells we also improve run times on wells that are not considered high fail.

DISCUSSION
Having a polished rod failure is sometimes overlooked, because it normally is a quicker repair and costs are relatively low. In some cases, polished rod failures can lead to other problems such as damage to sucker rods or corrosion issues during the downtime. This paper will discuss steps that can reduce polished rod failures at the clamp and also at the sucker rod connection.

Solids issues in the pump have increased as fracking has been expanded in newly completed wells. Several pump designs and accessories will be considered and the benefits along with any detrimental effects they can have. I will also discuss methods to eliminate sand from entering the pump.

Gas interference issues will also be addressed with a natural gas anchor. For wells that can't be pumped below the perforations, gas separation will be discussed for various size bottom-hole assemblies. In some cases, specialty pumps must be used as gas breakout continues in the pump even with good down hole separation. These methods and pump designs will be discussed along with any accessories that are available for gas issues.

SOLUTIONS
The polished rods support the entire weight of the rod string and fluid load along with the cyclic loading that accompanies rod pumping. This loading is not the cause of polished rod failures, because polished rods are commonly 100,000 psi tensile strength. Polished rod failures are fatigue type breaks due to misalignment causing a bending moment during the pumping cycle. Keep in mind that it is not uncommon for a polished rod to be cycled greater than 10,000 times per day. Some of the more common causes are pumping unit alignment, carrier bar alignment, or well head alignment. Any misalignment will be concentrated at the polished rod clamp as the polished rod moves into the stuffing box. This is the reason

nearly all polished rod failures are at the polished rod clamp. There are many causes of alignment issues that must be reviewed when you have a polished rod part. In some cases, the pumping unit bearings have worn causing a side to side movement in the pumping cycle. POC load cells can fall down into the window of the carrier bar causing a bending moment. Failures can be reduced by periodic inspection of the pumping unit, carrier bar, and POC load cell. An indication that a failure may be coming is extreme wear on one side of the stuffing box packing. Difficulty installing packing due to the polished rod being too far on one side of the stuffing box should be a tattle tale that alignment should be checked. Rod rotators benefit not only the rod string but also the tubing string. Rod rotators have bushings to accommodate the different sizes of polished rods used. Sometimes the bushings do not get installed and during the rotating of the rod a groove will form on the polished rod and eventually fail. Improper installation of the polished rod clamp is also an issue causing polished rod failures. The polished rod clamp has a specific torque value that should be adhered to. The installers should be aware of this value and given torque wrenches to assure the guideline is followed. Polished rods are relatively soft and must be protected by either a liner or a spray metal coating. Polished rod clamps should not be installed on the spray metal coating while under cyclical load. The spray metal coating is Rockwell C 48-52 and will crack due to the softer rod beneath the coating. Manufacturers furnished the rods with unsprayed sections for clamping. Increasing the bare clamping area makes it easier to space out the rod pump and in most cases lowers the cost of the polished rod.

When the polished rod fails at the thread, it's almost always due to the incorrect coupling used between the polished rod and the first rod down. Polished rods must use a coupling designed for a polished rod. Polished rod couplings have a mark on the coupling showing a PR indicating it can be used on a polished rod. API specification 11B 7.2.1.3, specification for sucker rods calls for all sub couplings manufactured for connecting different sizes of sucker rods have a polished rod thread. A best practice adopted by some operators is to have the polished rod thread and the first rod down different sizes. By doing this the well service crew is forced to use a combination coupling which will have the correct thread. Training for polished rod failure prevention should be given to employees and contractors to make them aware of the many items that can cause polished rod failures.

This paper will not cover best practices for design and handling of sucker rods and sucker rod couplings. Many handling classes along with design programs are available and should be utilized to improve sucker rod run times. The use of rod guides are growing as more deviated wells are drilled and completed. If you have certain types of coated tubing, be sure and use a rod guide that is compatible with that coating. Care should be given when using coated tubing to make sure all components will drift through the tubing. It is a good practice to add a rod guide on the top of the pull tube or valve rod of insert pumps. This practice has led pump shops to add them on the top of tubing pump plunger assemblies. Very often these guides will not go into the tubing pump barrel, requiring the retrieval of the plunger assembly and removal of the guide. Sinker bars added to the rod string help reduce rod on tubing wear that lead to rod and tubing failures. Producers have learned the coupling connecting each sinker bar can be matched to the OD of the sinker bar. This keeps the shoulder of the coupling from causing wear on tubing. This practice may require the use of slim hole couplings. Shear tools or on and off tools can assist in removing the rod string when an insert pump is stuck in the tubing. This also minimizes the chance that the rod string could be damaged pulling too much load while trying to unseat the pump. Care should be used when running pumps in with a shear tool installed. If the pump is running into the well too fast, it can scope in and then drop quickly shearing the tool. There have been many instances that a shear tool is blamed when it is actually a tight spot in the tubing that caused the problem.

SAND AND SOLIDS ISSUES

Sand can cause various issues in rod pumps including: stuck valves, cut barrels and plungers, sticking plungers, and pumps stuck in tubing. Sand must be somehow separated from the produced fluid and left in the well or produced through (handled by) the pump. Several separation methods have been used successfully, but the same method may not work in all wells. Some of the devices are just filtering the sand from the fluid and are subject to eventually plugging up. Other devices use centrifugal force or stages to trap the sand and dump it into the rat hole or a mud joint section to be pulled on the next tubing job. These sand separators are usually installed right below the seating nipple. Their design will not allow a dip tube or strainer nipple to be installed on the pump. I have witnessed pumps not seating because the dip tube or strainer nipple is hitting the top of the desander. One of the easier options is to raise the pump seating nipple to a position that the sand will not be entering the pump. This of course is dependent on your fluid level being high enough to reach the pump intake.

Pump designs for sand and solids can be as simple as increased plunger to barrel clearance or pumps like a Three-Tube Pump that is specifically designed to clean up a well. Each pump design may improve one well problem while having an adverse effect on another. A Three-Tube Pump has a high barrel to plunger clearance allowing solids to flow through the pump. Additional benefits of the Three-Tube Pump are, it is in effect a travel barrel and a stationary barrel pump at the same time. This helps keep the pump from sticking in the tubing but still allows you to run the thin wall barrel to moderate depths. Because the Three-Tube Pump is designed as a cleanup pump and not expected to have a long run time. There are three different pump designs to help with sand by excluding sand from entering the plunger barrel interface. The Pampa Pump uses a long plunger and a short barrel design. The sand will not enter the barrel because the plunger is always stroked out of the barrel. The Sand-Pro Pump® is another design that keeps sand from entering the plunger barrel interface. It is designed with an upper wiper plunger that handles the sand before it gets to the lower plunger. Between the upper and lower plunger is a connector that traps sand and balances the pressure above and below the upper wiper plunger. With no hydrostatic load on the wiper plunger, it has a long life handling the sand while the lower plunger is handling the pressure. (Refer to the paper SAND-PRO® CONGER FMT PRESENTATION presented at the 2009 SWPSC for additional information). Another design to fight sand is the Sand-Flush® plunger. The upper leading edge of this plunger has an angled face to stop sand from entering the plunger barrel interface. During the down stroke fluid is discharged through six vertical holes in the top of the plunger. This keeps the sand moving away from the plunger's leading edge. (Refer to the paper SAND FLUSH PLUNGER PERFORMANCE IN THE HWY 80 FIELD presented at the 2016 SWPSC for additional information)
The most effective way to avoid a pump stuck in tubing is to use a top hold-down pump design. Top hold-down pumps are a good example of a give and take scenario. The top hold-down pump is subject to the barrel splitting especially if the well is over pumped. The reason for this is the hydrostatic pressure is only on the inside of the pump and not on the outside like a bottom hold-down pump. There is a trend where producers are setting top hold-down pumps deeper than API recommendations. The reason they do this is because nearly all of their pumps have been stuck in tubing due to sand. They are willing to gamble on the top hold-down because of the expense and safety issues pulling tubing with a pump and or rods stuck in it. There are accessories that are added to bottom hold-down pump that mimic what the top hold-down does. They create a barrier between the top of the barrel and tubing keeping solids from the interface. One is the settable top seal the other is a Brush Sand Seal both are available for most bottom hold-down pumps. A sand check can be added to the top of most API pumps to stop sand from entering the pump. This inexpensive device is underutilized and should be added anytime there is the presence of sand. The producer should always consider the plunger to barrel fit when having sand issues. In some cases, you would prefer to tighten up the fit to exclude the sand from entering the plunger barrel interface. In other wells, it may be better to loosen the fit to allow sand to flow through the pump. Cage selection is also critical for wells producing sand. The ball in a standard three guided cage with an API pattern ball may stick causing valve fouling or can completely plug off. Changing to an alternate pattern ball gives an additional clearance for the solids to move through the cage. This is another decision that can have good and bad results. In the case where there are solids and gas interference, the alternate pattern ball will damage itself and the cage due to the additional clearance. You must decide which way is better by measuring your run time with the alternate pattern and without. My personal opinion is pump sizes 1-3/4 and above have large enough cages they may not need the alternate pattern. There are also cages designed for additional flow area that aren't as damaging to the ball and cage in the presence of gas. They have addition ball guides with different clearances that can be fine-tuned to your pumping condition. Plungers are damaged by sand being forced between it and the barrel interface by the hydrostatic pressure and by the plunger running over the sand during the pump stroke. The plunger will be grooved top to bottom causing fluid to slip through these grooves doing more damage. The use of a ring grooved plunger can help stop the top to bottom sand grooving. By having shallow ring grooves around the plunger every foot, the sand particles will get trapped in the groove. The particles will then get discharged up and out of the pump rather than cutting the barrel and plunger. The ring grooved plunger isn't as prone to stick in the barrel as often as a conventional plunger.

GAS INTERFERENCE

The performance of rod pumps will be affected by gas entering the compression chamber replacing fluid. Gas will compress and not allow the traveling valve to open at the top of the down stroke as it should. Just like sand, keeping the gas out of the pump is by far the preferred method. If you can set your pump intake below all of the casing perforations, then gas will rise in the casing annulus and the fluid will fall down to the pump intake. Wells that don't have enough distance between the bottom perforation and the plug back depth won't allow the operator to place the pump below the perforations. In today's horizontally completed wells this too will not allow placement of the pump below the perforations. If you cannot take advantage of a natural gas anchor, then a downhole gas separator needs to be installed. The simplest separator is sometimes referred to as a poor boy gas separator. If the separator is sized properly, it can be an effective tool to help with gas interference. Operators should strive to keep the downward velocity of the fluid/gas mixture in the dip tube/gas separator at less than six inches per second. Often operators use a joint of tubing with a perforated tubing sub as their separator. This is a very poor design and leads to a lot of gas issues in many wells. Please refer to the formula at the end of the paper to calculate your velocity rate based on your bottom-hole assembly and your pumping parameters.

Additional bottom-hole separators are available that use special methods to separate the oil and gas before it enters the pump. One design uses baffles to create turbulence that aids in breaking apart emulsions. Gas then moves up while the fluid is directed to the pump intake. Some of these designs also have solids separation built in for wells that have both issues. Other designs use a packer to create an artificial sump for gas free fluid between the tubing and the casing.

In some well conditions, gas interference will need to be handled with pump design. The key to overcoming gas interference in the pump is opening the traveling valve. The hydrostatic load on the traveling valve ball will hold it closed until the pressure below the ball is higher than the pressure above the ball. Various pumps designed for gas interference will accomplish this in different ways. One of the methods that has been around for 70 plus years is to add a sliding top valve on top of a conventional valve rod pump. This valve assumes the hydrostatic load on the down stroke allowing the traveling valve to open sooner. In my opinion this is one of the most underutilized products available for gas interference. This valve has the added benefit of closing off the top of the pump during any down cycle to exclude solids. Another pump design that is commonly used is a Two-Stage Hollow Valve Rod pump. This pump also has an upper valve to assume the hydrostatic load and also has two compression chambers. The lower chamber loads on the up stroke and then compresses that fluid into the upper chamber on the down stroke. That fluid is then compressed in the upper chamber again and up and out into the tubing. At the top of the upper compression chamber is a pull tube guide with about .030" of clearance between it and the pull tube. This allows solids to exit the pump, but can be detrimental because it can let the hydrostatic load slip by and defeat the value of this pump design. I recommend that this pump not be used on slow stroke or pumping units with drives. If this pump design will be running in a very deep well, a heavy duty pull tube design should be used to avoid premature failure. A very similar pump is the Gas Chaser pump working much like the Two-Stage HVR with the two compression chambers. One of the differences is the upper chamber has a precision fit at the top rather than the .030" clearance. This makes this pump a true compound compression pump to handle a high gas oil ratio. Many times this pump is used when pumping below a packer where there is no place for the gas to vent. A completely different pump design is the Variable Slippage Pump that has a tapered barrel section in the pump at the top of the upstroke. Once the plunger reaches the top of the tapered section the pressure equalizes above and below the traveling valve ball and seat. This allows the traveling valve ball to open quickly on the downstroke and the gassy fluid mixture to move into the tubing. Any rod pump that has gas coming through it cannot be as efficient because gas is going replace fluid in the compression chamber. The producer should make sure the pump is designed and assembled correctly for a gassy well. The Pampa pump and the traveling barrel pumps are excellent pumps for sandy conditions but are poor gas pumps. In cases where sand and gas are expected, a pump designed for both should be used. Standard pumps can also be poorly assembled where they become poor gas compression pumps. API recommends that the spacing between the standing valve and the traveling valve be no more than 2 inches. I would recommend that the spacing between your valves be no more than ¾ of an inch. Producers must also be careful to properly space out their well to achieve the highest compression ratio. If you are experiencing gas interference, then lower your rods to a point that you know the pump is spaced as close to bottom as possible. The compression ratio of a rod pump is calculated by taking the swept volume (actual downhole stroke), plus your unswept volume (area between the standing valve and traveling valve), and divide the sum by the unswept volume. Using the maximum stroke on a pumping unit will give the pump a higher compression ratio and that gives you a higher discharge pressure. Please refer to the table below for the compression ratio and discharge pressure calculations. The example shown is just for that particular pump design. Each pump design will have a different compression ratio and discharge pressure.

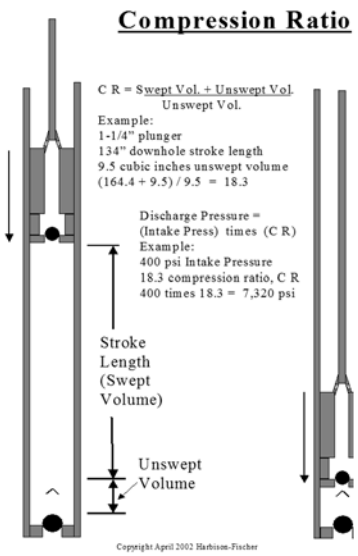
In a perfect pumping condition, the plunger will fall though the fluid without interference from either gas, solids, or over pumping. This eliminates many issues such as rod on tubing wear, valve rod or pull tube buckling, plunger pin failures, and many other failures. Since this is not the case in many wells, we must design for side loading on the pump. Starting at the top of the pump a collet connection is recommended when you must push the plunger into the barrel. This connection strengthens the valve rod or pull tube threaded area reducing parting in the last engaged threads. Heavy duty cages are available for the top of the Two-Stage HVR pumps where side loading and wear are causing failures. Collet connections where the valve rod or pull tube threads into the plunger coupling will also reduce failures. Careful consideration of the plunger coupling and traveling valve cage will help eliminate failures. In wells that are not corrosive, steel components are the best choice. If corrosion is an issue, then Monel should be used instead. Monel is very corrosion resistant and has the strength of steel. If you have shallow production, then stainless might be an acceptable choice, but remember one pulling job can pay for many upgrades to Monel. Because of their heavier wall thickness, stainless steel can be used for the standing valves. In wells with high temperature chlorides above 150 degrees, avoid using any stainless steel components that might lead to chloride stress cracking.

DEVIATED WELL BORES

In today's wells deviation is the norm and must be addressed. When producing a horizontally completed well, pumping in the vertical section the preferred method. This of course is dependent on having the fluid at that point to produce. As mentioned above, gas separation will need to be addressed wherever the pump is set in a horizontal well. The second choice would be to place the pump in the horizontal section. The pump will operate in the horizontal section as long as it is not inverted. The third choice is the deviated section. When you place the pump in the deviated section, then the pump is being subjected to side loading every stroke. You can reduce the damage to the pump by placing it in the straightest section of the deviation available. Adding items to the pump like hard lined valve rod or pull tube guides can reduce the effect the side load has on the pump. Some customers have had improved run times by using a shorter plunger to help get around the curve.

CONCLUSION

Routine well review meetings will give the operator the opportunity to review failures and make changes to correct what they are doing wrong. Operators should include the pump company, chemical provider and field personnel operating the wells. The frequency of the meeting should be based on the operating area's failure rate. As the mean time between failures increase, the meetings can be reduced from weekly to monthly and finally to quarterly. It is important to have the information available at the meeting to review failures. This can include sample parts, pictures, and chemical analysis of solids. I have personally witnessed producers starting well review meetings and establishing a list of best practices reduce their well failures. This team approach should have guidelines and goal setting to be successful. Following best practices will lead to a reduction of total operating expenses and a safer work place.



HARBISON-FISCHER FORMULA for POOR BOY AND OVERSIZE GAS SEPARATORS	
V=	$\dfrac{(P^2)(S)(L)}{(60)(M^2-G^2)}$
P=	PLUNGER DIAMETER, INCHES
S=	STROKES PER MINUTE
M=	SEPARATOR (MUD ANCHOR) ID
G=	DIP TUBE OD
V=	CALCULATED VELOCITY OF FLUID/GAS MIXTURE IN DIP TUBE/SEPARATOR ANNULUS, INCHES PER SECOND