COMMON MISCONCEPTIONS AND PROBLEMS USING SUCKER ROD PUMPING FAILURES – REVISITED

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ABSTRACT AND SCOPE

In the past the author has presented several papers on this subject. This would be a third installment with new material and updated solutions based on new technology and experiences.

There are a lot of misconceptions about how Sucker Rod Pumping (SRP) systems work, which may result in problems that can be difficult to resolve. Misunderstanding of how the systems or components function can lead to erroneous conclusions about what has occurred. This paper will cover the basic physics and mechanics of an SRP system and how the components interact together to function properly. This paper will also describe how changing various mechanical parts of the system or changing operational practices can create unsuspected problems and equipment failures.

Downhole pump designs and common well problems caused by gas, sand, and corrosion will be discussed, and as well as operational problems due to misapplication and misuse of SRP systems. Recommended processes to aid in solving problems and extending the run life of SRP systems will also be examined.

INTRODUCTION

The root causes of typical pump failures can be broken down into four basic groups:

1. Misdiagnosis of well problems
2. Well conditions
3. Operational parameters
4. Misapplication

MISDIAGNOSIS OF WELL PROBLEMS

One of the most costly problems with sucker rod pumps happens when the downhole equipment is pulled to correct the problem, but the wrong pump or other equipment is used to replace it, so the original problem is not correctly identified – and sometimes the situation is made even worse. Often there is a failure to record sufficient evidence to identify the root cause, and sometimes there is a misidentification of the evidence that is recorded as "fact," and other times too many assumptions are used to make decisions about the corrective actions to be taken. From that point on, everyone involved in the corrective action is working in the wrong direction.

The corrective action team often relies on a perfunctory assessment of the current failure and ignores important clues that may be embedded in the history of prior failures, including analysis, notes, and data from past interventions. The historical data may also be incomplete, incorrect, or at least questionable. For example, the rig report may state the cause of failure was due to pump failure, but the pump teardown report states that the pump was in good, operable shape. So which one is correct?

The economic pressure to get the well back on production quickly does not permit a well to remain shut in and a workover rig to remain idle while the pump is torn down and inspected, samples are collected, and failed parts are examined before completing the workover job.

For example, a particular well experienced declined production, then it stopped pumping, and then the pump was allowed to tag for short time, after which the well resumes pumping again. The well produces gas, so a rushed conclusion is reached that the well becomes "gas locked" at times, and that the tagging cleared the gas lock. The focus then shifts to a new downhole separator, a high-GOR pump, and other methods to stop the "gas lock" problem. The well is pulled and the new equipment is installed, but nothing changes. At this point, the problem may indeed be compounded if the earlier erroneous conclusion of gas lock still drives the next steps, instead of taking a step back to reexamine the first conclusion.

In this particular case, there could have been three other causes of the problem:

- The pump tear-down report (received weeks after it was pulled) may have found that the problem is actually in the pump itself.
- Or it could have been a damaged ball with pitting over part of its surface, which can only seal when the ball seats on the undamaged sealing surface, but it leaks when it seats on the pitted surface.
- Or it could have been some rubber, scale, or other debris that caused the valve to stick open on some strokes and free up on others, finally sticking open to keep the pump inoperable. In this case, the tagging knocked the foreign material clear so the pump started to function again. If the debris in the well is not cleaned out, then the next pump may also operate inconsistently. A redesign of the pump and valves to function better with solids would also be a good part of new course of action, since the well may continue to have solids/debris problems in the future.

Most importantly, it may have been more cost-effective in the end to have waited for a quick tear-down of the pump at the well or a pump shop and have incurred some extra rig time to find the real problem than to return to the well for a second or even third workover to finally find and fix the real problem.

GAS PROBLEMS

Gas lock is often used to describe any gas problem, so here are two of the most common gas problems with a description of each and methods to fix each problem.

Gas Lock

True gas lock exists when the hydrostatic pressure on the top of the traveling valve ball is greater than the pressure exerted on the pump chamber side of the traveling valve at the bottom of the downstroke. On the upstroke the gas expands in the pump chamber, but the pressure in the chamber remains above the pump intake pressure, and the standing valve does not open. So in the case of true gas lock, the valves stay closed, and the same column of fluid is raised and lowered with each cycle with no fluid being pumped. The dynamometer card will show a flat "worm card" at the peak polished rod load area, because the traveling valve is not opening to release the fluid load and drop to the minimum polished rod load. If you are watching a gauge on the bleeder valve with the flow line closed, the pressure will rise and then drop back, but will not continuously build pressure after multiple strokes, as it would during normal operation. That is why gas lock and stuck valves are often confused. Adding double valve cages (both the traveling valve and standing valve) has resulted in returning many wells back to pumping that had been diagnosed with "gas lock."

Gas Interference

There are two different types of gas interference.

One occurs most often on new wells that flowed for a period of time and then dropped in production and a sucker rod pump was installed. What happens quite often on this type of well is the pump will contribute to the flowing, and the term often used is "flumping" (flowing and pumping). Sometimes this will balance out and the desired production level is reached, but more often the pump starts a gas-lift type of situation, and then the well unloads, blowing the tubing dry. Then the gas coming through the pump keeps the valves from functioning properly, and the well has to load back up with fluid before the pump starts to function again. During the period when the pump is not functioning or is functioning but fluid has not yet filled the tubing, the gauger will check the well and find that he cannot build pressure with the flowline closed, so he reports that the well is down. Most of the time the well will be pulled, and the pump will be checked and found to be in perfect operating condition. One of the best ways to combat this problem is to use a backpressure regulator to hold pressure on the tubing. Over the years we have found that the best method is to simply set the pressure by listening to the backpressure regulator and the flow line check valve. First, determine your polished rod size and downhole pump size. If the pump plunger OD is larger than the polished rod size, then the fluid will be pumped into the flowline on the upstroke. If the polished rod is larger than the pump plunger OD, then the displacement of fluid will occur on the downstroke. With your ear fairly close to the backpressure regulator you can hear the fluid and gas mixture as it rattles the valves in the regulator and the flowline check valve. Start adding pressure to the valve until you hear the rattling stop during the part of the cycle when the fluid would not be normally be pumped into the flowline. If the pump plunger OD is larger than the polished rod, then you will want to stop the valve rattling on the downstroke, and you only hear the gas/fluid chatter on the upstroke.

The more common type of gas interference takes place when gas is pulled into the pump chamber with the liquid and then expands due to the pressure drop in the pump chamber. This causes less liquid to enter the pump, resulting in poor pump efficiency. This type of gas interference also causes "gas pound" and the resulting sucker rod compression above the pump. The best way to combat this type of gas interference is to use a good downhole gas separator system (that subject is covered in many other papers available in the literature).

PUMPING SPEED

There are a number of problems with the terminology used in sucker rod pumping that can lead to misconceptions right from the start. One of these terms is the use of "strokes per minute," often abbreviated as SPM. There is actually a downstroke and an upstroke in each pump cycle, but the full cycle is always called a "stroke." Cycles Per Minute may be a more accurate term, but we will stick with SPM because it is the recognized term in use in the oil industry today. Just remember that each "stroke" in "strokes per minute" is actually the upstroke plus the downstroke it takes to complete a cycle.

The second most misunderstood concept is the speed of the pumping unit. Once again, the use of SPM can be misleading. SPM does give you the cycles per minute, but it does not tell you how fast the pumping unit, polished rod, sucker rods, and pump are moving. To get the average speed of the pumping system you have to calculate the linear speed.

Linear speed is important because the pumping unit can actually travel faster on the downstroke than the sucker rods can freefall through the fluid. This can cause slack between the carrier bar and the polished rod clamp, resulting in damage when they slam back together. This is also one of the causes of premature sucker rod failure and fatigue breaks in pumps due to deflection. Linear speed is not just the amount of time it takes to complete a cycle, but the number of inches covered in the cycle. This means that we have to consider the stroke length (SL) as well as the SPM. The simplified rule of thumb is to multiply the two, SPM × SL, to get the average speed in linear inches per minute. Another good rule of thumb, based on empirical data, is to not exceed 1,400 linear inches per minute.

For example, if the pump speed is 10 strokes/minute, and the SL is 144 inches/stroke, then the linear speed is:

$$SPM \times SL = 10 \times 144 = 1{,}440 \text{ inches/minute}$$

This as an "average linear speed" with conventional geometry units, but the stroke actually starts out at a speed of zero at the top, then accelerates positively to the middle of the stroke, and then decelerates until the end of the stroke, stops, and then reverses. The speed of the rods at any point in the downward or upward cycle will depend on the pumping unit geometry, and in the middle of the up- or downstroke the rods are traveling at a velocity much greater than the average linear speed. Enhanced geometry units usually have a faster downstroke and a slower upstroke so as to have the same average SPM to shift the permissible load. Table 1 is from the Lufkin catalog for maximum rod fall. These formulas do not work in heavy viscous crude but predictive design programs like Srod and Rodstar can predict rod fall in viscous crude if the proper damping factors are used.

The rule of thumb of keeping linear speed to 1,400 inches/minute or less is a good general guideline, but at times you may need to push this to a higher rate, especially with longer stroke lengths. When that is necessary, the formulas from the Lufkin pumping unit catalog (see Table 1) work quite well. Programs for rod string design like S-rod and Rodstar can predict downhole buckling (deflection), and these are more accurate in predicting rod fall if the correct data is used.

BROKEN PARTS DUE TO DEFLECTION

The majority of parts we have examined over the years are fatigue breaks due to deflection. Besides the excessive speed problem described above, the most common causes of the deflection are:

- Fluid pound
- Gas pound
- Well bore deviations (planned and unplanned)
- Tubing movement and tubing anchors that have slipped, putting the tubing in compression.

Fluid Pound

Fluid pound is one of the most common and most destructive operational problems that can cause deflection of the sucker rods, pull rods, and pull tubes. This phenomenon will cause fatigue-type breaks in the pump or the rods above the pump, and will also cause friction wear on parts when the sucker rods are deflected into the tubing wall, sending impulse waves through the parts and causing threaded parts to unscrew. Various methods are often used to control fluid pound: timers, vibration controls, pump-off controllers, and well controllers (smart controllers).

Timers are quite effective, but adequate manpower resources are required for this method. To get a good timer setting, someone has to remain on site to monitor the well's performance for hours at a time for a number of days. Well inflow data and pump performance data can be used as a starting point, but to really fine-tune the timer settings, hands-on monitoring is usually necessary. Additionally, changing reservoir conditions will require occasional re-setting of the timers to prevent pounding fluid or under-producing the well.

Vibration controls are good tools to detect mechanical problems with the pumping unit and shut it down, but these should not be used for pump-off control. The problem is that considerable damage may occur downhole before the vibration is transferred to the unit.

Pump-off or well manager controllers usually work with a load cell for load, an inclinometer, or more common now a Hall Effect sensors for position. The Hall Effect sensors allow the setting of a threshold, usually at the beginning of the downstroke, on the downhole dyno card. If the traveling valve does not open at the beginning of the downstroke, the controller will read this as fluid pound. Most units allow the threshold to be adjusted and also allow for a repeated number of strokes before the unit is shut down, but this is where problems occur. If the threshold is set too far into the downstroke, the force of the freefalling plunger will increase and cause damage. For example, if the unit is set to allow 7 strokes before shutdown occurs, and this happens 10 times a day, you would have 490 fluid pounds a week or 1,960 per month. Over time this can cause cyclic fatigue, friction damage, and loose connections.

Gas Pound (Gas Interference)

Another source of deflection is gas pound, which is one of the problems caused by gas interference. Gas pound is similar to fluid pound, but instead of the freefall and collision that occurs with fluid pound, gas in the fluid starts compressing, which slows the downward acceleration, resulting in a cushioning effect. This helps limit the force and impact, but still causes the sucker rods, valve rods, and pump parts to deflect. One of the most common symptoms is that the pump is not delivering the production it should, and the erroneous conclusion is that the pump needs to be replaced. This happens often and is a costly problem because it often misunderstood.

When a pump is not pumping efficiently, it is best to have a dynamometer test and also conduct a pressure test by closing the flowline for a few strokes to see if the pump builds pressure. If the fluid is mostly gas, it will build pressure slowly with each stroke, and a bleeder valve sample will also lose part of its volume as gas breaks out and evaporates. Quite often the percent of gas breakout in a sample will match the percent of gas pound on the dyno card and be close to the percent of efficiency the pump has lost. When this is the case, there are really only a few choices:

- Build a good downhole gas separator to eliminate as much the gas from the pump intake as possible;
- Use a larger pump (and live with the inefficiency) and use sinker bars to counter the rod compression; or
- Use a pump that allows the traveling valve to equalize at the top of the stroke and eliminate the rod compression (Variable Slippage Pump®).

Wellbore Deviations

Horizontal drilling is very popular, and if the well is drilled with a target of 10°/100 ft build rate, it can be pumped successfully with a sucker rod pump with few problems. Most horizontal wells drilled in the last 10 years have a wellbore survey, and this can be used to pick the best place to land a pump. Survey data can also be used in certain computer programs to determine the ideal number and location of sucker rod guides.

Pump failures can occur when the pump is placed in an area with a rapid rate of change in the dogleg severity. Worn valve rods and guides are the most common problem caused by wellbore deviation, but these can also result from gas compression and tight plunger fit. In one unusual example, a 3¼-inch diameter plunger with all of the sprayed metal worn off of the outside of the plunger had a barrel that was oval-shaped on the inside, and one side of the barrel bore was almost worn through. This was due to severe deflection of the pump. The plunger was worn out all the way around its circumference because they had a rod rotator on the well.

Other examples of problems due to dogleg severity include broken valve rods, broken plunger adaptors, or even broken plunger pins. When unusual wear is apparent a through the tubing gyro deviation survey can be used to get an exact measurement of the rod on tubing side loading and locations.

DOWNHOLE PUMP RECOMMENDATIONS FOR DEVIATED WELLS

The well deviation survey should be used to find an area with the least amount of deflection and the least rate of change over a distance of at least 1½ to 2 times the pump length. The type of pump, whether it is held down at the top or bottom, and the overall pump length need to be considered in deciding where the position of the seating nipple is to be located. For example, if a top hold-down pump is used, the seating nipple should be at the top of the straight section so the length of the pump is in the desired location.

Experience has shown that rod pumps work fine in most wells with build rates from 4–16°/100 ft, with a few functioning properly in the 18–20°/100 ft deviation range, depending on pump length. Some horizontal wells have been produced with the downhole pump in the curved section at 30–45° into a 90° curve, but these experienced short run times. Build rates of 5–7°/100 ft have proven to be ideal for long pump run times, but a rapid rate of change can still result in an area that will have high-side loading. A schematic of the downhole horizontal well and the setup for a top hold-down pump that has been used successfully is shown in Figure 1. This arrangement can prevent plugging of the pump intake and allows some gas separation from the pump.

Carbide sleeves have been used in the pull tube guide to stop wear, but the plunger and barrel still had accelerated wear when trying to pump in a curved section. The pump life was typically less than one year, and the plungers showed a distinctive, teardrop-shaped wear on each end.

In vertical wells, gravity plays a major part in seating the balls, as it has been shown that the sucker rod pump valves open by pressure differential and close by fluid flow. This is especially useful for operating in sucker rod pumps in horizontal wells, as documented above; however, while gravity helps, it is not essential for proper valve action. If during operation a late valve closing is observed on a dynamometer card, then spring-loaded cages may be helpful, but these added springs can fail over time.

UNANCHORED TUBING

In wells that have a large fluid load differential between the upstroke and downstroke (large F_o load), unanchored tubing movement can sometimes cause enough deflection to cause damage to the pump as well as to the casing. For example, a group of wells in which top hold-down pumps were used were operating at 2,900 ft to 3,200 ft. The hold-down body was being broken at the barrel bushing, and frictional wear was found on the bottom OD of the pump barrel. The sucker rod couplings, valve rod, and guide showed frictional wear consistent with deviation-type damage. The tubing movement, although small at this depth, was being deflected due to some wellbore deviation, causing the pump damage. Pump anchors were installed, and the failures declined to almost zero.

SLIPPED TUBING ANCHOR

A tubing anchor that is slipping can cause deflection problems all up and down the tubing string. This usually occurs when the anchor slips do not have the proper contact force against the casing. The loss of tension allows the anchor to slide up and down as the fluid load is shifted on to the tubing during the downstroke, and again when the fluid load shifts to the rods on the upstroke. This can often be picked up on a downhole card or pump card, as shown in Figure 2.

CORROSION PROBLEMS

There are many different downhole corrosion problems that can affect the sucker rod pump. Acidic corrosion is one of the most common, and the acid is created from bubbling gas through produced waters. H_2S and CO_2 are the most common. NACE specification MRO176 provides the following guidelines as to what might be expected:

- High concentrations of CO_2 at low pressure are not corrosive, i.e., in shallow wells less than 1,000 ft.
- Mild metal loss will occur when water cuts are less than 25%, H_2S is less than 10 ppm, and CO_2 is less than 250 ppm.
- Moderate metal loss will occur when water cuts are between 25% and 75%, H_2S is between 10 ppm and 100 ppm, and/or CO_2 is between 250 ppm and 1,500 ppm.
- Severe metal loss will occur when water cuts are over 75%, H_2S is greater than 100 ppm, and CO_2 is 1,500 ppm.

The thing to note here is that as water cut increases and if H_2S or CO_2 content is right, corrosion will become a problem, even in wells that have no history of corrosion. As a field ages it is a good idea to start checking pH levels and having water samples analyzed. Some additional caveats are:

- Do not run chrome-plated steel pump barrels in wells with fluids that can act as a good electrolyte, as a galvanic cell could form. Micro-cracks in the hard chrome can allow a galvanic cell to form and progress through the wall of the barrel. Brass chrome or nickel carbide on brass is a better choice for this condition.
- Do not run stainless steel parts if high chlorides are present and the downhole temperature is over 150°F. Use brass or Monel parts instead.
- Because stainless steel has a yield strength that is half that of carbon steel be careful of running stainless steel parts in deeper wells. Monel has higher yield strength than stainless steel and may be a better choice for these applications.

PERFORMANCE DATA

For sucker rod pumping, run time in days can be misleading because loading and wear of the rod pump system depends on the number of cycles, not the length of time. For example, a group of wells that are operated at 10 SPM are going to complete twice as many cycles (reversals) per day as another group of wells that operate at 5 SPM, yet we still like to compare failure data of the two groups in days.

Days run before failure or using Mean Time Between Failure (MTBF) has been used for so long for other oilfield equipment that it is accepted without question, but sometimes this can cause data to be skewed and misapplied. The primary downfall of run time in days is that most of the fields operating today have a wide variety of operating conditions from well to well. For example, at 10 SPM a sucker rod pumping system will complete 14,400 reversals per day, or 5,256,000 cycles a year. This means that the rods have stretched and contracted, the pump barrel and tubing have had the fluid load shifted on and off of them, and most of the other pump parts have been subjected to stress reversals and wear over <u>five million times</u> in a single year.

Various factors make it difficult to use "days in operation" as the primary decision-making criterion – or even a valid key performance indicator (KPI) – for sucker rod pumping systems. Such factors include: strokes per minute, different stroke lengths, the use of timers and well controllers, as well as the variety of different pump sizes employed to meet operational needs. Rather than MTBF, the number of cycles and the magnitude of reversals should be considered as the primary baseline unit for comparison. All of the components of a sucker rod pumping system have a certain lifetime, but it should be measured in cycles (reversals) and the magnitude of those reversals. If optimization programs involve changing the SPM of wells over the course of a year, then MTBF starts to break down as an accurate measure of performance.

Most historical records, however, will be in "days of operation" units, and such data should be converted to cycle units, if possible, to be able to "compare apples to apples." For example, if a group of ten wells, five of them operating at 16 SPM and the other five operating at 8 SPM were compared based on average days of run time and based on the number of cycles, the data would look something like the chart in Table 2. Based on <u>days</u> to failure, the conclusion would be that because Group One at 16 SPM ran 181 days while Group Two at 8 SPM ran 319 days, then Group Two systems would have performed almost two times better than Group One. However, if the true performance measure of <u>cycles</u> to failure were used, then Group One at 20,851,200 cycles vs. Group Two at 13,781,440 cycles would tell a totally different story.

The load on the system must also be considered, because different pump sizes, rod strings, well depths, etc., will produce different peak and minimum polished rod loads that affect the lifespan of sucker rod pump systems. A second chart compares the peak polished rod load and minimum polished rod load for each well can be very enlightening.

HOLD-DOWN INFORMATION

There are two main designs of seating nipples and hold-down assemblies: the cup design and the mechanical design.

Cup Design

This hold-down type uses nylon/plastic or a rubber/canvas composite material for the seating cups that are usually 0.030 inch larger than the internal diameter (ID) of the seating nipple. When the cups compress to fit in the seating nipple, this creates a seal and provides the force to hold the pump in place. This "<u>plus thirty</u>-thousandths" of an inch over the nominal ID of the seating nipple is all that is needed to seat and seal an insert pump. This design is called a +30 cup.

It is important to know that there are "Precision" API seating nipples and "Standard" non-API seating nipples. The recommended best practice is to use API seating nipples; however, some wells do have non-API nipples.

In the case of the $2^{3}/_{8}$-inch size, the nominal ID is the same for both API and non-API seating nipples, and both use a $1^{25}/_{32}$-inch +30 cup. However, there is a difference in $2^{7}/_{8}$-inch nipples: the non-API one uses a 2¼-inch +30 cup, and the API one uses a 2¼-inch +70 cup. Therefore, it is very important to know which type of seating nipple you have in the well. Also, a 2-inch RWA pump will not go through the $2^{7}/_{8}$-inch non-API nipple, but it will go through the $2^{7}/_{8}$-inch API nipple. Be careful, because you may see a reference to a +30 +40 seating cup instead of +70, but they are one and the same, and +70 is typically what will be on the seating cup box.

Mechanical Design

This type of hold-down relies on a spring that pulls a metal seal surface on the hold-down against a metal seal in the seating nipple. Mechanical-type seating assemblies are used when the temperature is too high for plastic or composite seating cups, and when greater force is required to keep the pump seated. The two main styles are API Top Lock and API Bottom Lock. Because the API Bottom Lock does not allow attachment of a gas anchor or strainer nipple to the bottom of the pump, an adaptor can be used to convert a API Top Lock to work as a Bottom Lock.

Table 1 – Equations to Use for the Different Types of Units
(L = Stroke Length)

For Conventional Units:	$SPM = .7 \sqrt{\frac{60000}{L}}$
For Air Balanced Units:	$SPM = .63 \sqrt{\frac{60000}{L}}$
For Mark II Units:	$SPM = .56 \sqrt{\frac{60000}{L}}$

Table 2 – Comparison of Wells using Run Days vs. Cycles

WELLS AT 16 SPM	**RUNS IN DAYS**	**CYCLES**
#1	188	4,331,520
#2	182	4,193,280
#3	190	4,377,600
#4	176	4,055,040
#5	169	3,893,760
TOTAL RUN TIME AVERAGE	**181**	
TOTAL CYCLES		**20,851,200**
WELLS AT 8 SPM	**RUNS IN DAYS**	
#6	321	2,773,440
#7	333	2,877,120
#8	289	2,496,960
#9	312	2,695,680
#10	341	2,946,240
TOTAL RUN TIME AVERAGE	**319.2**	
TOTAL CYCLES		**13,789,440**

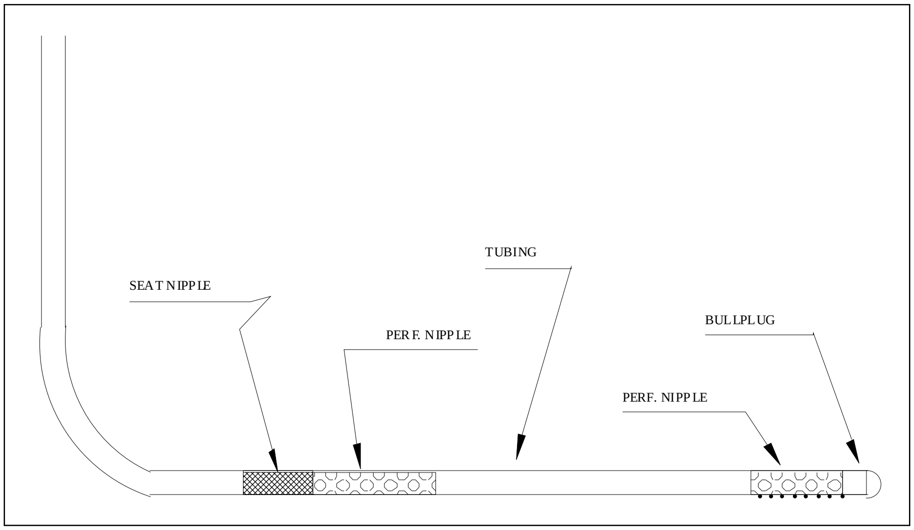

Figure 1 – Top hold-down pump in a horizontal well

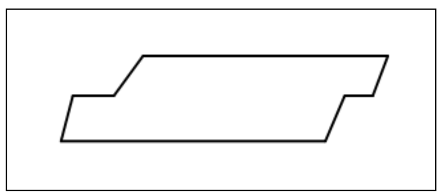

Figure 2 – Example of a downhole dynamometer card with a slipping tubing anchor