EFFORTS TO REDUCE THE COST OF STUCK PUMPS

Steven Gault, Cisco Perez, Steve Reedy, and Saul Tovar
Occidental Petroleum

ABSTRACT

Historically, as many as 30% of bottom hold-down pumps have gotten stuck, resulting in extra costs associated with pulling tubing for pump repairs or rod failures. This paper focuses on various tools and techniques that have been used to reduce the number of pumps that get stuck in the tubing.

Introduction

Occidental Petroleum's Permian Enhanced Oil Recovery (EOR) business unit operates many water floods and CO_2 floods in the Permian Basin. Unseating pumps has been an ongoing problem, and efforts are being made in multiple areas to address the causes and improve well performance.

Discussion

Under normal conditions, the pump will unseat with a pull of a few thousand pounds greater than the cumulative weight of:

- The rod section in the fluid (accounting for buoyancy effect),
- The rod section above the fluid, and
- The net force of the fluid on the plunger (accounting for the U-tube effect).

However, if the pump is stuck, substantial additional pull could be required to unseat it. It is important to understand the maximum pull that can be exerted on the string before plastic deformation occurs, damaging the rods. Figures 3, 4, and 5 identify 90% of maximum pull on for 76, 86, and 87 API design steel rod strings respectively.

Once the maximum pull is determined, the following technique has proved to be successful in many cases:

- Pull to 70% of yield and leave for 15 minutes.
- Relax the pull, and pull to 80% of yield and leave for 15 minutes.
- Relax again, then pull to 90% of yield. Leave for 15 minutes.

Use a straight, steady pull, as opposed to a shock load, to achieve these load levels. Do not jar pumps to unseat them. If the pump still has not become unseated, try loading the tubing-casing annulus prior beginning the process of pulling the tubing.

Pressure Differential

If you are having difficulty in the process of unseating a pump, one contributing factor may be the pressure differential between the fluid inside and outside the tubing. It may be beneficial to decrease this differential pressure by raising the hydrostatic head in the tubing-casing annulus. At Occidental, this is done by pumping an adequate volume of produced water or brine down the annulus. Building some hydrostatic pressure under the pump helps offset the full column of fluid above the seating cups. This additional force will help the pump 'pop' from the seating nipple, unless it is being held in place by debris.

The main problem could be sediment that collects above the seating nipple between the tubing and the pump barrel on bottom hold-down pumps, as shown in Figure 1.

There are several tools available to restrict the accumulation of solids above the seating nipple in the annulus between the pump barrel and the tubing to make it easier to unseat the pump:

- Bottom Discharge Valves,
- Fin Elements,
- Top Seals,
- Mechanical Hold-Downs,
- Seating Shoe Seal, and
- Top Hold-Down Pumps.

Bottom Discharge Valve (BDV)

BDVs discharge a portion of the fluid on the downstroke from between the standing and traveling valves within the barrel to the annular space between the barrel outer diameter (OD) and the tubing inner diameter (ID). This effectively eliminates the dead space near the bottom of the pump, protecting the tubing and barrel with corrosion inhibition and reducing the amount of solids that can pack in around the barrel above the hold-down. BDVs should be used only when:

- Solids are identified as the reason for an insert pump sticking in the tubing.
- The well depth is lower than that recommended for a top hold-down. (Top hold-downs may be preferred at shallow depths.)
- There is not significant amount of gas being produced. The bottom discharge valve increases the unswept volume in a pump and is detrimental to the compression ratio.

Our experience has been positive, and running these BDVs is now a common practice at Occidental.

Fin Elements

This low-cost option keeps solids from falling between the pump barrel and tubing. Experience suggests that:

- Variations in the weight of rods when running in the hole lead us to assume that the fins may be hanging up when running in the hole, and equipment damage may be occurring.
- This is supported by the fins having significant rubber loses when they are pulled out of the hole.

In the past, it was a common practice at Occidental to run these fin elements, but recently they have fallen out of favor.

Top Seal

In theory, top seals would limit the solids accumulation above the seating nipple between the tubing and pump barrel by sealing off the top of an RHB, RWB, or RXB pump. This option is currently being evaluated.

Mechanical Hold-Down

A cup hold-down has a lip that limits how far the hold-down can go into the seating nipple to position the cups. This lip is a larger diameter than that of a mechanical hold-down, so a cup can be harder to unseat when fill has collected. Results of a recent pilot program suggest that mechanical hold-down could be a favorable option.

Seating Shoe Seal with No-Go Stop

Tubing pumps use a different type of seating nipple, the seating shoe, which has a beveled stop on the bottom that acts as a no-go and does not have the increased cross-sectional area that the cup type has. This seating shoe can be run in applications other than tubing pumps.

A pilot program is in progress, and early evidence suggests that the seating shoe seal can replace the cup-type seal without any adverse effects and can be unseated more easily.

Top Hold-Down Pumps

Gas separation and depth must be considered when running top hold-down pumps.

The preferred separator is a natural gas separator run below the bottom perf. If that option is not available, a modified poor-boy or collar-type separator is recommended. The outside diameter of the pump is larger than the typical dip tube in a poor-boy gas separator, and gas separators may have to be modified so that the downward fluid velocity in the gas separation chamber does not exceed the bubble rise velocity.

Top hold-down pumps also have a depth limitation. The section of the pump barrel below the seating nipple and above the valve supporting the hydrostatic head of the tubing experiences burst pressure. This is the force exerted by the fluid in the tubing minus the pressure exerted by the fluid in the tubing-casing annulus. As a result, top hold-down pumps have a depth limitation, whereas bottom hold-down pumps do not.

Experience to date with top hold-downs has not been positive. About 30% experienced premature failures, which appeared to be from solids. The implication is that the top hold-down pumps do not process solids as effectively as bottom hold-down pumps.

UNSEATING THE PUMP LOAD TESTS

A major downhole sucker-rod pump manufacturer conducted tests on the normal or typical loads or forces needed for a downhole pump to become unseated. Table 1 provides the test results showing the typical load or force that should be needed to pull the pump from its downhole assembly.

When unseating the pump, the weak link in the system is the top rod in the bottom taper (see Figure 2). Figures 3, 4, and 5 show the amount of force that can be applied at the surface without exceeding the 90% of the yield strength of the top rod in the bottom taper for 76, 86, and 87 designs, respectively. These graphs are based on API RP-11L.

The maximum load is plotted on the Y-axis for various depths on the X-axis. One should choose the appropriate API rod taper design, which varies by pump diameter, and read the maximum pull, which is defined as 90% of yield strength. When pulling to the maximum load, one should be aware of the load rating of the "S" hook and the rod elevators. This load should not be exceeded, as it is the maximum recommended rating of this equipment (20 tons for Weatherford RH-20, and 35 tons for RH-35).

Concern has been expressed over the accuracy of the pulling unit weight indicator. The rod stretch can be measured along with the estimated force required to stretch the rods. The calculated force to stretch the rods can be compared to the weight indicator to confirm that the limits are not being exceeded.

References:

API RP 11L – Design Calculations for Sucker Rod Pumping Systems (Conventional Units), API Technical Report 11L, Fifth Edition, June 2008.

SWPSC Paper, "Design Your Rod String to Unseat the Pump – But Not Overload the System," Hein/Williams/Stevens/Patterson, April 2006.

Table 1 – Force Needed to Unseat Pumps with Various Hold-Down Values

Type Pump	Insert	Tubing	Insert or Tubing	Insert
Location	Top or Bottom	Bottom	Bottom	Top
Type of Hold-Down	Cup	Cup	Mechanical	Mechanical
Tubing ID, Inches	Force To Unseat w/o Pressure, Lbf	Force To Unseat w/o Pressure, Lbf	Force To Unseat w/o Pressure, Lbf	Force To Unseat w/o Pressure, Lbf
1.5	425		1100	
2.0	500	500	1100	1000
2.5	650	650	2000	1200
3.0	740	740	1250	2500

Source: SWPSC Paper, “Design Your Rod String to Unseat the Pump – But Not Overload he System,” Hein/Williams/Stevens/Patterson, April 2006

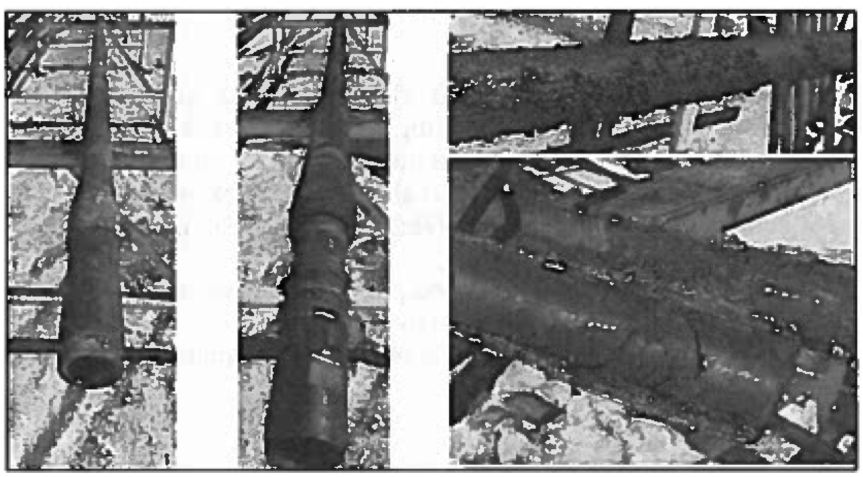

Figure 1 – (Left) The entire assembly as it appears coming out of the well; (Center) How the tubing was cut; (Upper Right) Solids on the pump barrel; (Bottom Right) Tubing split in two to show solids accumulation inside the tubing.

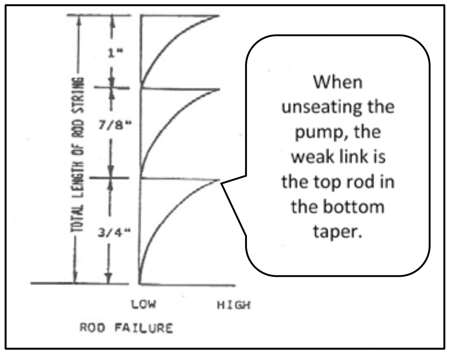

Figure 2 – Location of the Weak Link in Pump Unseating Operations

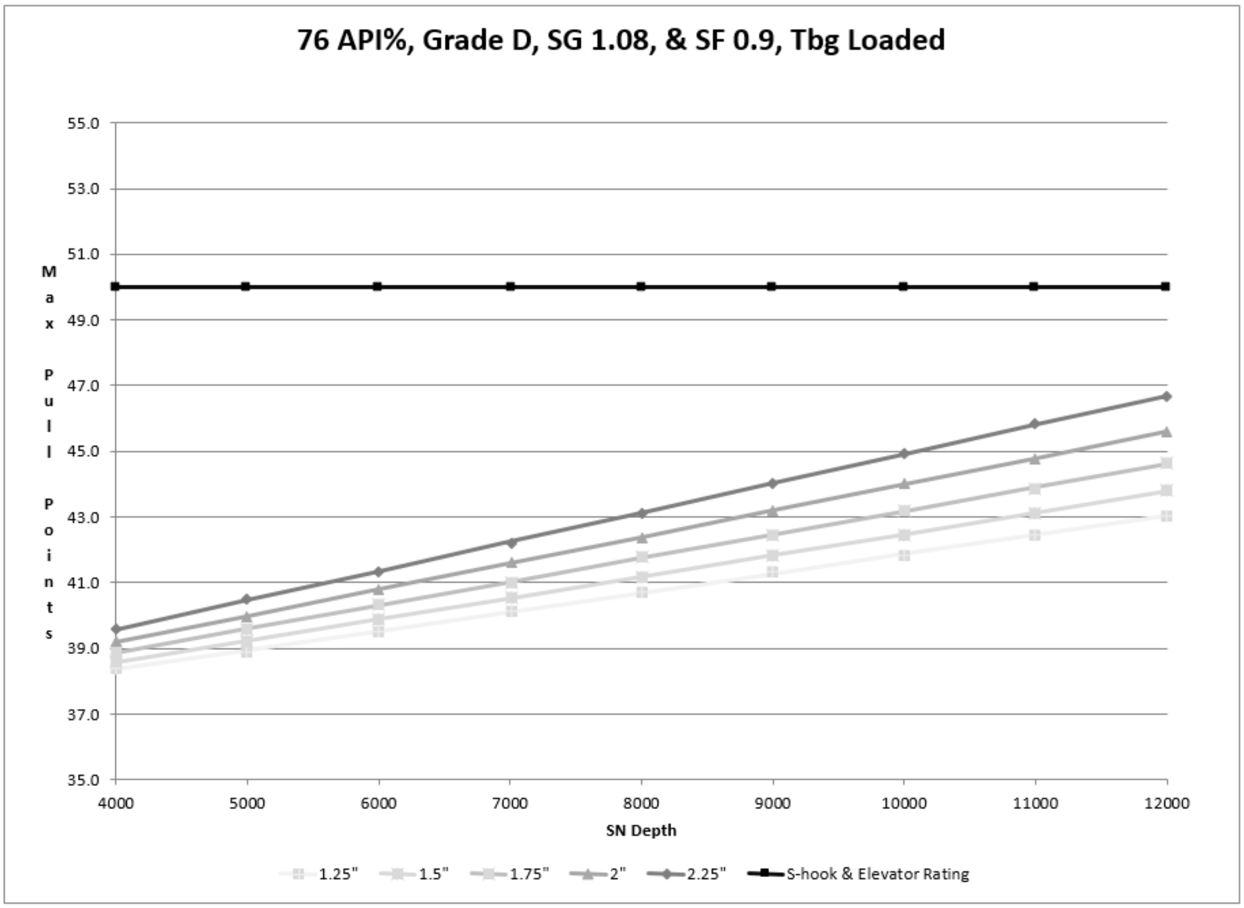

Figure 3 – Maximum Pull Guidelines for 76 API Tubing of Various Diameters

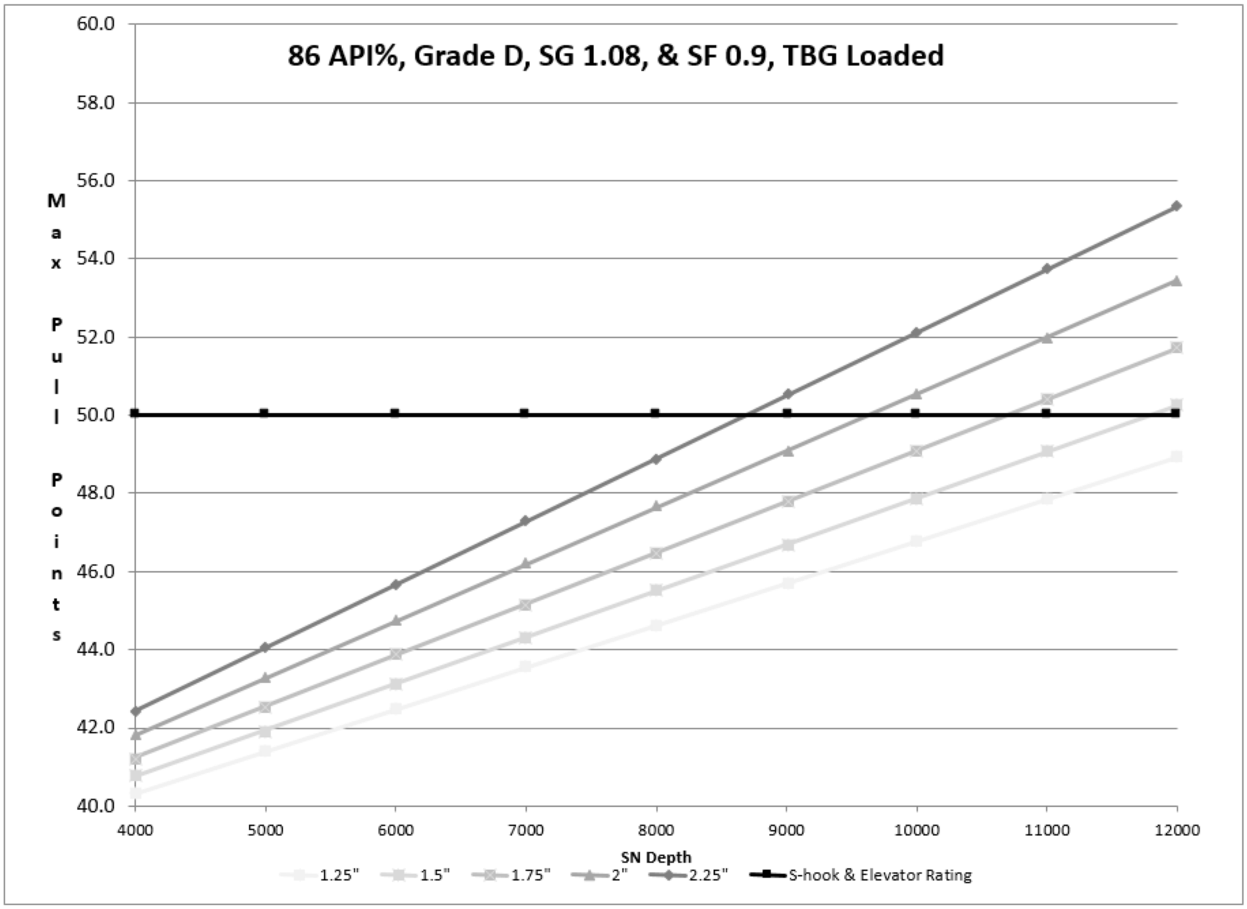

Figure 4 – Maximum Pull Guidelines for 86 API Tubing of Various Diameters

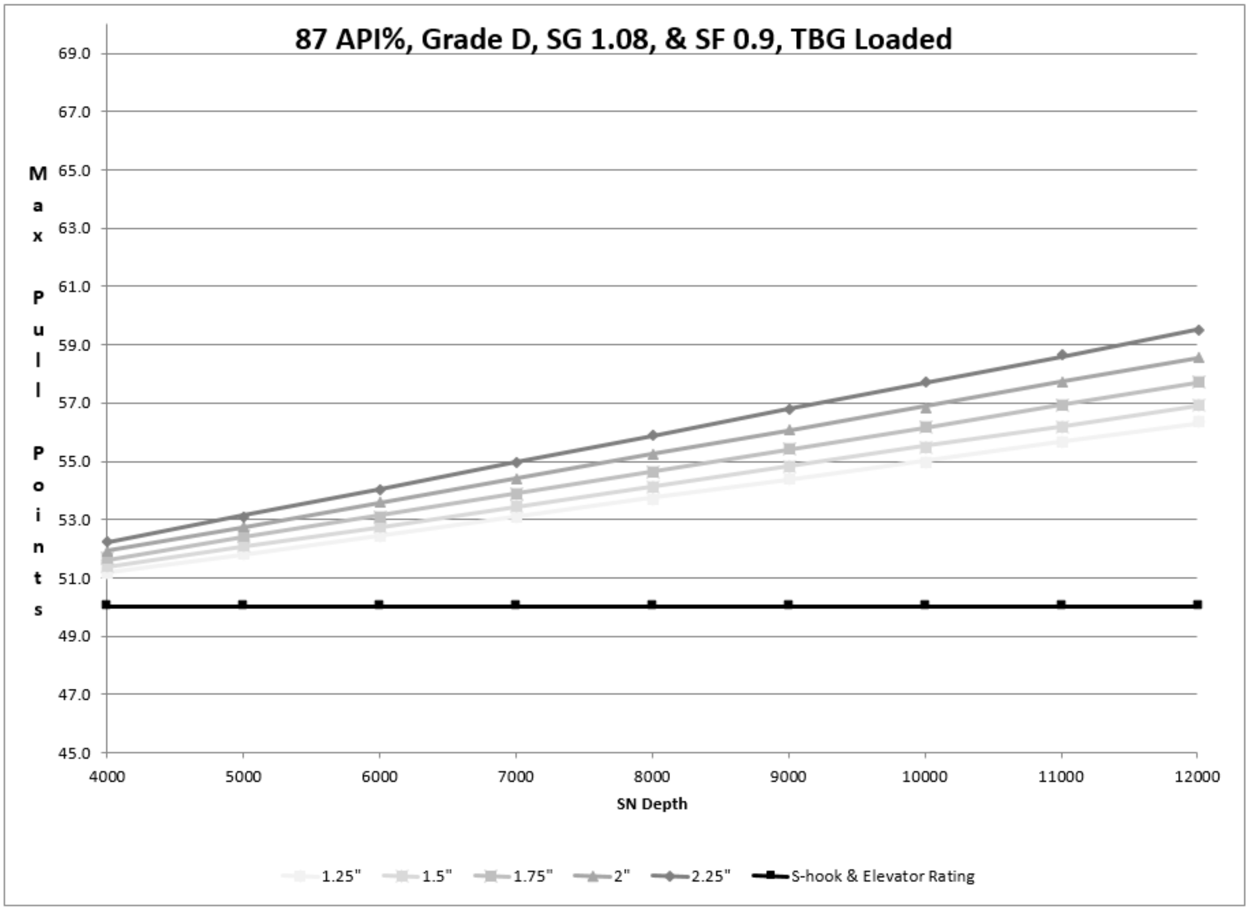

Figure 5 – Maximum Pull Guidelines for 87 API Tubing of Various Diameters