HIGHER COMPRESSION SUCKER ROD PUMPS

M. Shane Sims
Halliburton Energy Services, Inc.
Dennis Blair
Texaco, Inc.

Abstract
While operators are always searching for new techniques to produce oil more efficiently, the economic climate in which the oil industry finds itself today has renewed efforts to seek out new opportunities to improve operational strategies. This paper will discuss a field scenario in which gas locking problems were impacting production in a mature field in West Texas operated by Texaco. This field was being produced with CO_2 injection and was experiencing increases in beam lift failures and high CO_2 production.

After reviewing the conditions, the service/engineering company suggested a change in the pump configuration to increase the compression. A higher compression rod pump is an advantage for operators especially where gas is a concern. To accomplish the higher compression, the pump was built with the least allowable amount of unswept volume between the traveling valve and standing valve. By positioning the two valves as closely as possible and eliminating as much unswept volume as possible, positive results were experienced.

Eliminating gas lock and having to long stroke wells can be of great assistance in saving money for operators. This, in turn, can eliminate the use of gas breaking devices, which can be costly. The experiments with some of the Texaco Sundown Slaughter Field wells with high CO_2 production have shown improvement on efficiency and gas lock. As a result, the operator will also see reduced fluid pounding, which will increase the life of the equipment in the well, and thus, provide higher efficiencies and longer equipment run times.

Background
With the economics of the oil industry today, even when operations are not experiencing difficulties, there is still the need to be more efficient in all areas of operation. This need requires analysis of each and every phase of an operational scenario. The introduction of new technology and remedies has been of great assistance, however, more innovative techniques are still needed to address some of the problems that continue to be experienced. One of the biggest expenses for an operator in a mature field results from beam lift failures. It is also a fact that these failures seem to be worse in CO_2-injected fields. Where CO_2 or gas is the primary concern, there also appears to be increasing experience of low efficiency problems, along with fluid pounding.[1] These factors, in turn, can cause equipment failures of all types and the additional increased expenses of workovers.

Field History
The engineering/service company running the sucker-rod pumps for Texaco in some CO_2-produced wells began to investigate the reasons for the increased incidence of equipment failures and the increases in CO_2 production in January of 1996. The specifications for the pump at that time required the use of a bottom discharge valve but no particular type of "gas breaking" device. With this 2-1/2 x 1-3/4 x 20 x 24 rod pump heavy wall barrel-type (RHBC) pump (25-175-RHBC-20-4-3-1), materials had been upgraded enough to defeat the corrosion problem caused by CO_2.

Over a short time, however, CO_2 production increased — and pump failures with it. The efficiencies on the pumps were continuing to drop, and the types of pump failures were related to fluid pounding. Also, the problems of failing rod parts, tubing wear, and rod-coupling wear seemed to correlate to the wells that had the low pump efficiency.

To address the problems, personnel from the service/engineering company and Texaco formed a team, the sole purpose of which was to focus on pump problems. The primary responsibility of the team was to improve the Sundown Slaughter wells' sucker-rod pump performance. The initial analysis of the component failures indicated that a majority of the problems could be attributed to gas locking problems,[2] and thus, the sucker rod pump design. Since a possible solution would be to get the most compression possible in the pump to help compress gas, the following changes to the pump were suggested:

1. The "high compression" pump would need to be built with the least amount of unswept volume as possible.
2. The unswept volume would include any volume between the traveling valve and the standing valve inside the pump seals that was not swept or filled with pump during production.
3. In short, the two valves would need to be as close to each other as possible.

To provide a solution for the problem, the recommendation was to incorporate an inverted standing valve into the traditional pump design. The traditional pump is shown in **Fig. 1.**[3]

Design Changes

The "inverted standing valve" is simple in design. A bushing that connects directly to the holddown assembly of the pump was made. It was then screwed directly into the barrel. The bushing has another set of threads on the barrel end that adapts to the standing valve cage. The standing valve cage is now inside the barrel; therefore, it is the same size as the traveling valve. By making these changes, the distance between the standing valve and traveling valve was decreased from 9 in. to 5 in. Thus, the dead space in the pump was reduced by 57%. The closer valve spacing creates maximum compression ratio for compressing the gas in the pump. The pump employing the "inverted standing valve" is shown in **Fig. 2.** The only change remaining is to space the travelling valve as close as possible to the standing valve when the pump is installed in the well.

The operation of the valve is based on raising the compression ratio. If the pump is gas locking, then it is not getting complete fillage.[4,5] The reason it is gas locking is because it is full of gas rather than fluid. On the down stroke, the gas is compressed, and there is not enough pressure to open the travelling valve. Then, on the up stroke, there is still pressure on the standing valve. The gas has enough pressure that it will prevent fluid from entering through the standing valve and will prevent the pump from producing fluid. This cycle continues until there is finally enough fluid buildup in the annulus to provide the pressure required to open the standing valve.

For example:

1. The valves are 10 inches apart in the pump design (whether it be from a bottom discharge valve being between them or just a regular standing valve cage).
2. The hydrostatic load in the tubing is 2000 psi for a 4,500-ft well. (That 2000 psi pressure is on both the travel valve and the standing valve.)

When the volume between the valves on the start up-stroke is doubled, the pressure on the standing valve is cut in half. Therefore, if there is a 10-inch volume at the lowest point of down stroke and 2000 psi, then, the pressure is 1000 psi at 10 inches on the upstroke because there is only 20 inches of total volume. At 30 inches of upstroke, there is total volume of 40 inches (10 inches initial plus 30 inches upstroke). The total volume has been doubled again, and now, the pressure is 500 psi. Similarly, at 70 inches of upstroke, the volume doubles again and is now 250 psi. Finally, at 150 inches of upstroke, 125 psi is reached. If the bottomhole pressure coming into the pump is less than 125 psi, and there is only 120 inches of stroke on the unit, then, the standing valve never opens. The reason for its remaining closed is that there is still more pressure on top of the standing valve than there is below it, and now the pump is on its down stroke. When the valve does not open, there is no fluid in the pump — and the pump is gas locked. If the barrel has fluid (which does not compress) in it, it will open the valves of seat and pump.

The "inverted standing valve" operates as follows:

Example:
The operation starts with 5 inches of volume instead of 10 inches as in the previous example. At 5 inches on the upstroke, the pressure has been cut to 1000 psi. At 15 inches, the pressure is 500 psi. At 35 inches, 250 psi, and finally, at 75 inches of upstroke, the pressure is only 125 psi. The pump has done in 75 inches of stroke what it took the other pump 150 inches to do, and there is still upstroke left.

Since the first installation of the "inverted standing valve" approximately 50 of these have been installed. They have increased pump efficiencies in most all cases. Some people have a concern about the fact that the flow area through the standing valve has been reduced, but this has not reduced the efficiency of the pumps.

Case Histories

Case No. 1 —The first test recorded was on 3 January 1997 at well SSU #1089. This well had been completed with a submersible pump and had experienced gas problems. It was decided by Texaco to run a sucker rod pump in this well. A pump was built to the old specifications and was run into the well. The pump only pumped at 50% efficiency, and therefore, was pulled the next day to inspect for failure. When no failures were found, the pump was run back into the well for another trial. The pump ran another day but was gas locking and continued to pump at only 50% efficiency.

The well was producing 228 mscf/D gas, 180 BWPD, 40 BOPD, with 168-in. stroke length, at 7.4 strokes/minute, with an 1-3/4-in. bore pump, running at 100% of the time, at this time. The new pump design was suggested. As soon as approvals to make this change were received, the pump was pulled and the suggested pump design was run in into the hole.

The first test results showed 228 mscf/D gas, 315 BWPD, and 75 BOPD, with the pump running 100% of the time at the same parameters as before. These results were calculated, showing an 88% efficiency. On 1 January 1999, this well was producing 335 mscf/D gas, 124 BWPD, and 75 BOPD, and was running 55% of the time. This was calculated at 82% efficiency.

Case No. 2 —The next success was achieved 2 July 1997. Well SSU #1247 was producing 199 mscf/D gas, 242 BWPD, 34 BOPD, and was running 99% of the time at 144-in. of stroke, 7.5 strokes per minute, with a 1-3/4-in bore pump. This was was calculated to be only 52% efficient. The "inverted standing valve" was run, and the last test showed the pump to be 82% efficient. It was producing 271 mscf/D gas, 127 BWPD, and 32 BOPD, with all the same parameters.

Case No. 3 —The last case history comes from well SSU #2010. This well was recorded on 1 September 1997 to be at 23% pump efficiency. The well was producing 285 mscf/D gas, 102 BWPD, 34 BOPD, and was running 100% of the time with a 1-3/4-in. bore pump. The stroke length was 144 in., with 8.25 strokes per minute. The pump was pulled on 8-January 1998 and the "inverted standing valve" was run. On the next test, (1 February 1998) the efficiency was 100%. The well was producing 494 mscf/D gas, 340 BWPD and 99 BOPD, and the pump was running 100% of the time. The parameters were all the same.

New Design Enhancements

Design changes are now being made to the bushing area of the new pump design (**Fig. 2**). In this change, shown in **Fig. 3**, the cage and seat size is reduced to the same size as the cage in Fig. 2. This innovation should increase operational efficiency even more.

Conclusions

If an operator can obtain higher compression ratios in pump operations, the chance of fluid pounding and gas-lock conditions could be significantly reduced. The increase in efficiency that this would generate will increase oil production since higher compression results in higher pump efficiency. This efficiency, in turn, helps to reduce sucker rod, tubing, and pump failures by reducing wear and fatigue on the equipment. Additional advantages are that workovers to "long stroke" the pumps to break gas lock as well as to replace equipment will be also be minimized. The above advantages will all combine to increase operational cost efficiency for the operator as has been seen on the Sundown Slaughter Unit for Texaco. Finally, the reduction in workovers will enhance safety of personnel.

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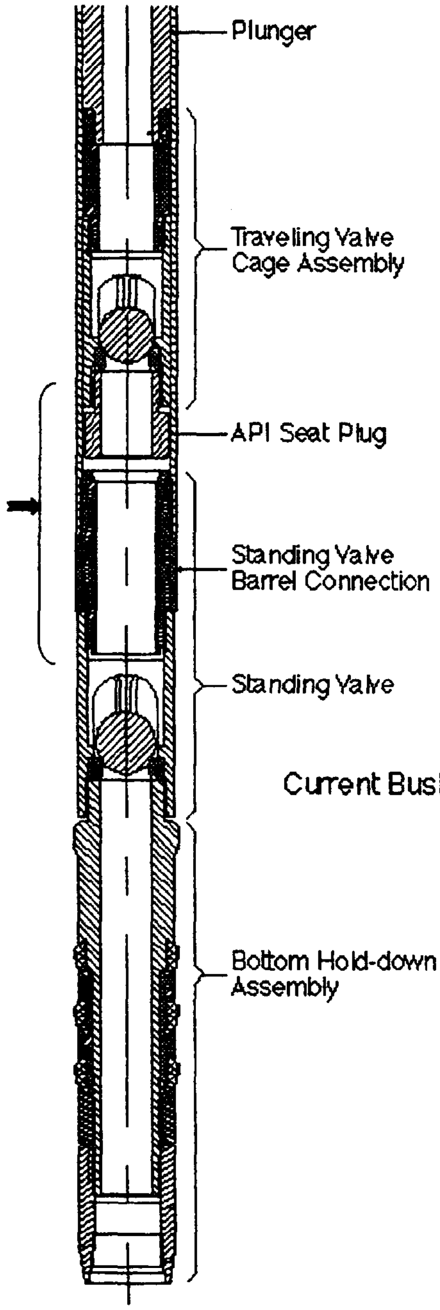

Figure 1 - Conventional Sucker-Rod Pump
The bracketed section with the arrow is the area of concern for the design changes.

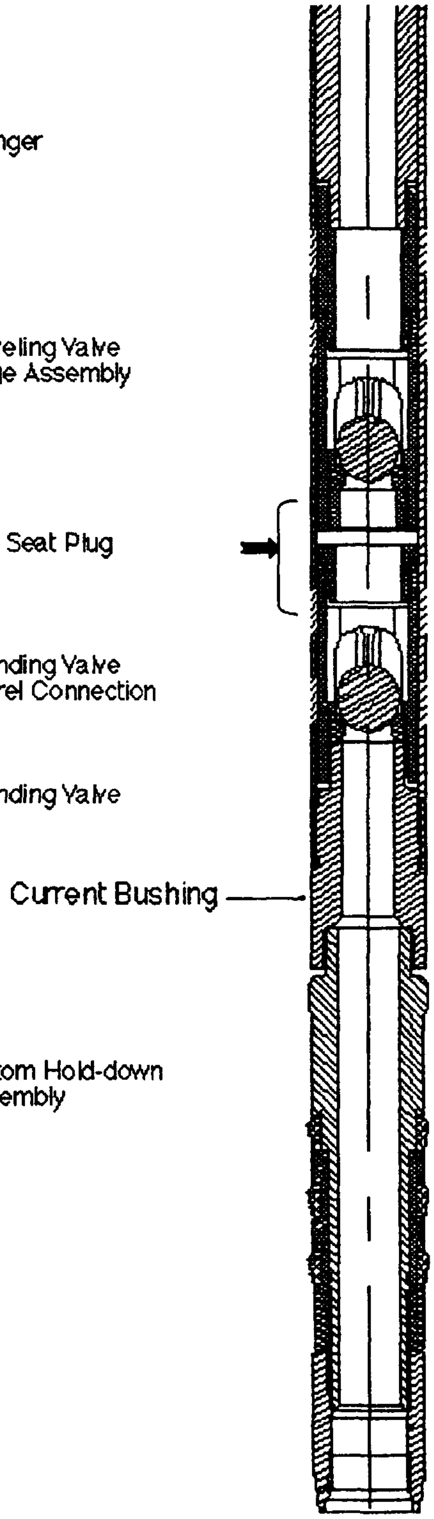

Figure 2 - New Pump Design
This design shows the change in the bracketed area size, which reduced the volume or dead area by 57%.

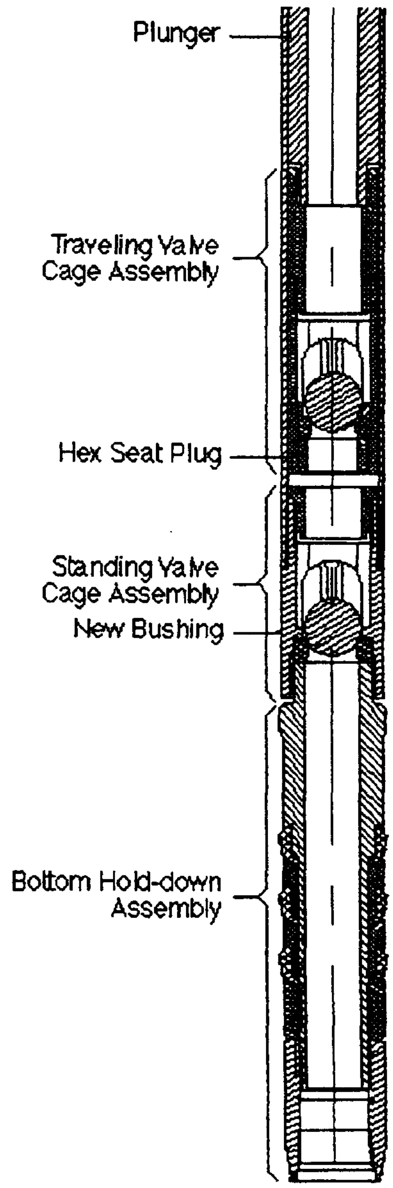

Figure 3
This figure shows added enhancements in process in which the bushing/cage area is reduced in size to that of just the cage in Figure 2.