SUMMARY OF TESTING OF VARIABLE SLIPPAGE PUMP (VSP) FOR GAS LOCKING CONDITIONS IN DOWN-HOLE SUCKER ROD PUMPS

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ABSTRACT AND SCOPE

The Harbison-Fischer Variable Slippage Pump, (VSP), has been field tested since December 1999 in wells located primarily in West Texas and New Mexico. Results have been favorable in gas locking conditions by eliminating gas locking, and increasing gas production in some wells. This paper will review the test data and the characteristics of these wells. It will also describe the fundamentals of this method of artificial lift, and present what was learned about pump component selection and downhole applications.

INTRODUCTION AND BACKGROUND

Slippage: A paper was presented at the 2000 Southwestern Petroleum Short Course (SWPSC) titled, "Fluid Slippage in Down-hole Sucker Rod Pumps."[1] This paper was the last in a series of progress reports that sequentially documented lab testing, field testing, literature reviews and theoretical studies of fluid slippage in sucker rod pumps. The conclusion was that the historical slippage equations significantly overestimated the amount of slippage and led operators to the use of plunger to barrel clearances that were too tight for most applications. Plunger to barrel clearances that are too tight do not allow enough space for proper lubrication or enough clearance for most fluid-borne particulates. The paper also offers a slippage equation derived from the studies. Based on these studies many operators in West Texas have been using looser fitting plungers and achieving longer run times with less plunger sticking problems. Mike Brock with ARCO and others have presented papers at the SWPSC winter forum that documented these results. Some of these results are listed in Table 5 of the above-referenced paper from the 2000 SWPSC.[1]

One side result of the slippage studies was the realization that other pumping characteristics were favorably enhanced by increased slippage, especially at the large end of the clearances studied. The largest clearance tested, .021" would not be usable in a normal pumping well. However, the pump raised fluid to the surface from 5,000', but at a low pumping efficiency of 25%.

Favorable characteristics of the large slippage amounts were; decreased peak polished rod load, increased minimum polished rod load and decreased pump friction. These were not the focus of the three year long study but were interesting findings. Some of these side benefits even showed up at reasonable plunger to barrel clearances.

Gas Locking: Many wells seem to be afflicted with gas locking conditions. Gas locking occurs due to several possible pumping conditions:

(1) Insufficient compression in the pump compression chamber to open the traveling valve on the downstroke, resulting in the pump not "grabbing a bite of fluid" on the downstroke. The result is that the pump does not produce any fluid on that stroke. The cause can be; too high of a gas to fluid ratio, poor pump compression ratio due to the valve rod being cut too short, or the pump being spaced too high at the well site.

(2) Insufficient un-compression in the pump compression chamber on the upstroke to open the standing valve and allow fluid to flow into the pump compression chamber. The result is that when the plunger starts down there is not any new fluid in the compression chamber for the plunger to capture and lift on the next upstroke, and no fluid is produced on the next upstroke. Insufficient un-compression is due to the same reasons as insufficient compression except that in addition there can be a lack of adequate fluid level over the pump to open the standing valve or a restriction in the pump intake.

(3) The well is flowing through the pump valves, holding them open and thus not allowing the pump to operate. This is generally not a pumping problem, since the well is producing gas and some fluid, but other problems such as a dry stuffing box and subsequent leakage can occur. Only the first two types of gas locking will be discussed in the following.

The gas locking pumping characteristics include fluid and gas production along with intermittent acceptable production and unacceptable periods of no production. The API 11AR recommended method of diagnosis is to lower the pump plunger until the pump tags, then raise the plunger to its normal position after the gas lock is broken by the mechanical shock. Sometimes this restores the pump to functioning but often the pump must be left tagging in order to maintain production at an acceptable level. This type of mechanical abuse is hard on the pump, the sucker rods and the tubing.

THEORY

The H-F Variable Slippage Pump. (VSP): All pump companies and many inventors and operators have come up with ways to address the gas locking problem, mostly through mechanical opening of the traveling valve on the downstroke. This attempts to solve type (1) gas locking.

It was realized that the goal of mechanically opening the traveling valve on the downstroke was to raise the compression chamber pressure by another means than normal compression of the fluid. This led to the idea to allow some fluid pressure above the plunger to bypass the plunger near the top of the upstroke, and thus achieve the same goal of raising the compression chamber pressure, so that the traveling valve could open on every stroke.

The VSP pump uses the principle of increased slippage near the top of the upstroke to allow pressure to equalize above and below the traveling valve before the traveling valve starts its downstroke. Thus the traveling valve does not need to build up pressure in the compression chamber to open on the downstroke. The pressure is already high enough to open the traveling valve at the start of the downstroke.

Several methods of bypassing fluid near the top of the upstroke are possible. These are being tested or have been tested by Harbison-Fischer and are covered in the Harbison-Fischer patent. The method that seems to best fit manufacturing methods as well as down-hole sucker rod pumping is a gradually tapered upper barrel. With this method a standard RH lower barrel is used for the primary barrel and the tapered VSP upper barrel is attached on the top. In this manner the operator can choose the length of the lower barrel to fit production conditions and use the upper VSP barrel as needed to fine tune the well production characteristics.

The length of the lower, normal barrel is shorter than usual and only needs to allow for the downhole stroke and twelve inches (12") for spacing. The length of the VSP barrel is nine feet (9'). The length of the upper extension above the VSP barrel accounts for the plunger length, fittings length, sucker rod stretch and normal spacing allowance, less the VSP barrel length of nine feet (9'). See figure 1.

It was thought initially that the VSP pump would negate the use of high compression cages and fittings in the pump compression chamber. However, it was realized that type (2) gas locking could still occur if good compression ratio pump parts and practices were not used. The VSP pump can cure type (1) gas locking by raising the pressure in the compression chamber to that needed to open the traveling valve on the downstroke, but it can only help with type (2) gas locking be venting some of the gas around the plunger when the pressure is bypassing the plunger. It is theorized that not enough time is available for complete gas venting during pressure bypass, and that downward moving fluid will prevent complete gas venting. In addition, if the pressure is above the bubble point then gas separation will not occur.

A consideration was that the slippage bypass would be unacceptable to operators. However, initial calculations showed that a slight taper would allow enough fluid to bypass the plunger and equalize the pressure without causing unreasonable slippage. **Also,** it was noted that the slippage amount was variable. By spacing the plunger higher or lower an operator could increase or decrease the slippage, or by pumping in the lower barrel below the tapered barrel eliminate the additional slippage entirely. Operators said that they would gladly give up some efficiency to cure gas locking problems.

FIELD TESTS

The prototype was successfully tested in August of 1999. Field tests started in December of 1999. To date eight (8) field tests have been completed. Several examples of these will be discussed below:

(A) Installation Date: December 1999

A *6,000'* West Texas stripper well that produces about 3 Barrels of oil per Day (BOPD), 3 barrels of water per day (BWPD), and 6 thousand cubic feet of gas per day (6 MCF). Before installation of the VSP pump the pump had to be tagged to operate and production was erratic. Installation of the VSP pump alleviated the need to tag the pump and production leveled out to consistent readings each day. This pump was pulled for inspection in May of 1999. No wear was noted and the pump was run again in the same well. **It** is still operating in this well.

(B) Installation Date: January 2000

A 6,150' West Texas stripper well that produces about 3 BOPD, 3 BWPD, and 7 to 8 MCF gas. Before installation of the VSP pump this pump also had to be tagged to achieve production. After the VSP pump was installed the pump did not require tagging and production leveled out to consistent readings each day. This pump has not been pulled since installation.

(C) Installation Date: June 2000

An 8,500' West Texas well that produces about 12 BOPD, 90 BWPD, and 100+ MCF gas. Although this well had a good production history it required regular operator attention and adjustment. After installation of the VSP pump the well has produced consistently without problems and gas production has increased. The pump is still installed in this well.

(D) Installation Date: February 2000

A new 8,000' West Texas well. Apparent gas locking caused pulling of the well several times for installation of various pumps for gas locking conditions. None were successful. The well would make fluid as well as flow off with gas several times daily. A VSP pump was installed with initial success but it went down the same day and could not be made to produce fluid or gas. A dynamometer test the next day revealed that one of the valves was stuck open with trash. The VSP pump was pulled and a standard H-F Two Stage Hollow Valve Rod Pump was installed with double valves, and with an alternate ball in one of the double valves. This solved the trash problem, the new pump operated successfully and we learned that accurate diagnostics are necessary for successful use of the VSP pump. The VSP pump could have been re-installed with double valves with an alternate ball in one of the valves to handle the trash, but the gas oil ratio (GOR) for the well was not high enough to dictate the use of the VSP pump.

SUMMARY

Several items were learned during field testing:

Sucker Rod Stretch: The fluid load bypasses the plunger before the plunger reaches the top of the upstroke. Therefore, the fluid load is transferred to the standing valve and the sucker rods un-stretch earlier in the pumping cycle than normal. Allowance is made in the pump by running a longer pump than normal to allow for sucker rod stretch.

A benefit is that the fluid load is transferred more smoothly resulting in fewer oscillations of the sucker rod string on the downstroke. This was observed on the dynamometer card during prototype testing.

Increased Minimum Polished Rod Load: In a normal pump the plunger compresses the fluid/gas mixture in the compression chamber during the downstroke. This puts an upward, compressive load on the sucker rod string during the downstroke. The VSP pump was observed on the same dynamometer card to have a higher minimum polished rod load, which should lead to fewer sucker rod problems due to this reduction of the sucker rod stress range.

By reducing or eliminating compression of sucker rods on the downstroke an operator should also experience less sucker rod buckling and thus less sucker rod and tubing wear above the sucker rod pump.

Elimination of Fluid and Gas Pound: Since fluid bypasses the plunger and equalizes the compression chamber pressure by filling the compression chamber before the downstroke, fluid and gas pound were eliminated.

Amount of Taper in VSP Pump Barrel: Several graduations of taper were tested. John Laney of OXY and Benny Williams of H-F presented a paper at the winter SWPSC forum where Mr. Laney showed that a more gradual taper produced a smoother load transfer during fluid bypass. The taper being used now is half of the original taper. This taper results in better control of the fluid bypass as well as smoother load transfer.

Point of Load Transfer: It was determined from dynamometer tests that the fluid load did not transfer an appreciable quantity of fluid until the bottom of the plunger entered the tapered part of the barrel. This follows from earlier slippage testing results since the length of the plunger has less of an effect on slippage than does the clearance between the plunger and barrel.

Efficiencv: A reduction in pump efficiency was noted on each field test. Some were greater than others due to the amount of gas being produced. However, all were acceptable given that the gas locking problems were solved.

Diagnostics: We learned that the VSP pump could be used for diagnostic testing of a well to determine if the reason it was down was due to gas locking or trash in the valves. By spacing the plunger high in the taper it was possible to completely backfill the compression chamber and distinguish between gas locking and trash interference in a valve.

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ARCO
OXY
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Devon
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TWS Pump
Liberty Pump
Alliance Pump

REFERENCES

(1) "Fluid Slippage in Down-Hole Rod-Drawn Oil Well Pumps," by John Patterson, ARCO, Jim Curfew ARCO Permian, Mike Brock ARCO Permian, Dennis Braaten, ARCO Permian, Jeff Dittman, ARCO, Benny Williams, Harbison-Fischer, Southwest Petroleum Short Course, 2000, pp 117-148.

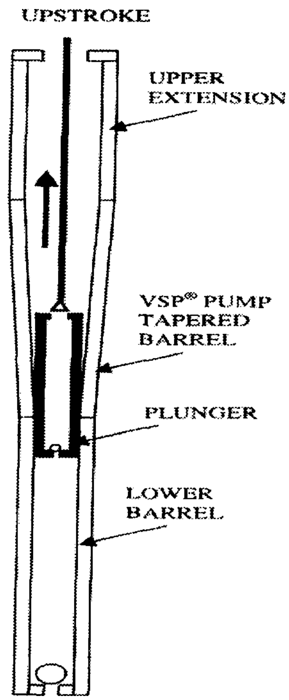

Figure 1