THE IMPORTANCE OF COMPRESSION RATIO FOR PUMPING GASSY WELLS

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A true gas lock is really just a pocket of gas trapped between the standing valve and the traveling valve. It has enough pressure when the pump is extended (on the upstroke) to keep the standing valve from opening and admitting new fluid. But does not compress tightly enough when the pump is closed (on the downstroke) to lift the traveling valve off it's seat.

Since coming to the oilfield in 1975 I have seen, and dealt with a great number of sucker rod pumps that appeared to be gas-locked. I have also inspected, and listened to the sales pitch for, many devices that the inventors claim will solve this problem once and for all.

I have had the opportunity to evaluate several of these "gadgets" in the field and found them wanting. Most often the devices fail prematurely, and several had no discernable effect. The claims for others bordered on the absurd.

Yet, these devices persist and I have seen at least three inventors and or salesmen in the last six months. At least two of the ideas have merit, although not necessarily for the reasons that the inventors' claim.

As a well technician for Texaco I have been involved in the company's ongoing process of educating its' personnel. To this end I have attended two short courses on sucker rod pumping. Both of these schools have emphasized that "bumping", "tagging", "snigging", "poping", or any of the other names for allowing the pump clutches to contact at the bottom of the stroke are undesirable.

The possible damage to the pump is obvious, but the shock to the rod string, pumping unit and tubulars is frequently overlooked and often leads to premature failures. Most operators do not realize that a "nipping" pump is producing tons of force more than 1/2 mile below the surface.

I have seen pumping units with broken bases and cracked pedestals that were attributed to "tagging" the pump. Although this is a severe case, it is probably not uncommon.

Most petroleum engineers have been alerted to this problem at some time during their education. In the real world, though, engineers in this country seldom visit the wells they are responsible for. Field personnel, foremen, pumpers, and gangs make the decisions that lead to "tagging" the pump.

Although the field personnel recognize that "snigging" the pump is detrimental, they will insist that there is no other way to clear the gas lock. However, they are often under the misconception that "jarring" the valves delivers the desired result.

What most people don't realize is the that there are an astounding number of pumps that gas lock intermittently. I did not realize this until reliable pump off controllers became available a few years ago. What I found was that many of my controllers were shutting down due to a perceived low load span.

After spending a considerable amount of time investigating the possibility that the controller was at fault, I finally determined that it probably was not. One day while investigating a particularly balky well, (low load span was shutting it down several times a week) I decided to release the casing pressure to the atmosphere. Having determined that the fluid level was at or near the seating nipple, I opened the off side casing valve. As the casing pressure neared atmospheric pressure the pump suddenly gas locked. The instantaneous change in load was at first interpreted as a rod part by all present. I closed the casing valve.

A field crew was called and the rods were lowered several times while we checked to see if the pump would "tag lightly" by running the unit through several strokes after each lowering of 2 inches or so. After lowering the pump several times (a total of about 8 inches) the pump suddenly started working again. It never "tagged". This was not the end of the problem though, and we were forced to lower the rods again later, to "tag the pump" constantly to insure that it pumped.

Later, a new well was drilled in an old primary production field. When first pumped everything seemed fine. By the next morning though we had about five barrels on the ground around the well head and a new pumping unit that had to be steam cleaned. It was assumed that the tubing had "flowed off" allowing the packing in the stuffing box to overheat and burn out.

A BAIRD backpressure valve was installed on the tubing and I set the pressure at 300 psi. The fluid level was less than 1000 feet from surface and I felt that the pressure would keep gas from "flowing" the tubing dry. When the fluid level was lowered a new problem cropped up. The stuffing box again leaked.

One day I found it with the rods parted. I reported this to the foreman and later that day I was told that the well was not parted, but the pump was changed. I realized too late that I had happened across another gas lock. Soon thereafter the rods were lowered to the point that the pump was tagging very hard. The stuffing box continued to seep in spite of everything the lease operator could do. Several types of packing were tried and a polished rod lubricator was installed.

In the spring of 1991 I was informed that a sucker rod pumping school would be held in Levelland to be instructed by Bob Gault. I requested and received permission to attend. I had been to one of Bob's schools a year earlier and found his presentation intriguing.

During the course of his talk Bob touched on the importance of compression ratio in building a sucker rod pump. He mentioned pull rod length and the use of hex type seat plugs, as he described a proper pump design. The ideas on compression were new to me.

My first step when I returned home was to visit three local pump shops. I asked if they cut pull rods from rod stock and if hex type seat plugs were available. I found that two of the three shops cut valve rods from stock. None of the three had hex type seat plugs in stock, though two of the shops knew how to get them.

I selected the Axelson shop in Kermit Texas to perform an experiment. I had a 2 1/2 x 1 1/2 x 22 ft. RHBC pump built with a hex type seat plug and a plunger to end of barrel clearance of 1/4 inch. With the indulgence of the foreman in charge it was installed in the second of two problem wells previously described.

The results were phenomenal, the pump no longer gas locks, the polished rod packing has not needed replacement, the polished rod lubricator has been removed, production has leveled out, and the well has given us no trouble in the last 18 months. Most important though, was the fact that the pump was not tagging to produce these results.

I was told that the pump that was removed had a plunger to end of the barrel clearance of more than one foot. This was due to the use of a precut valve rod.

The success of this first experiment led me to investigate the subject even further. I first took some rough measurements of the unswept volume in the standing valve cage and the traveling valve of the subject pump (2 1/2 x 1 1/2 x 22 ft. RHBC). This calculated to be about 3.8 cu. inches. I next calculated the unswept volume of the plunger to end of barrel distance of one foot (using Pi r^2 h) and obtained an additional 21.2 cu. inches, for a total unswept volume of 25 cu. inches.

Assuming that surface stroke length was close enough to plunger stroke length for these purposes, and the surface stroke being 120 inches I then calculated a swept volume of 212 cu. inches.

Using the compression formula:

$$CR = \frac{SV + USV}{USV}$$

Where: CR=Compression ratio-number, which when multiplied by the suction pressure, gives the maximum discharge pressure for the compressor or pump.
SV=Swept volume-total volumetric space covered by the piston or plunger travel.
USV=Unswept volume-area of the cylinder or pump that the plunger does not cover in its stroke.

The compression ratio was calculated to be 9.48. I also assumed that the intake pressure would be about 50 psi if the fluid level was at the seating nipple. Thus, multiplying the compression ratio by the intake pressure yielded a compressive pressure inside the pump of 474 psi.

The well is about 5800 ft. deep and I also made the assumption that in a worst case scenario the tubing would be full of produced water. This calculates to a load on the traveling valve of about 2600 psi. Obviously, a compressor that can generate only 474 psi cannot pump against an opposing force of 2600 psi.

The pump we had replaced it with (2 1/2 x 1 1/2 x 22 ft. RHBC with a hex type seat plug and a plunger to end of barrel distance of

1/4 in.) has a total unswept volume of about 3.5 cu. inches. The length of stroke and therefore the swept volume remains the same, yielding a compression ratio of 61.57. With a 50 psi intake pressure this compressor can generate 3078 psi, more than enough to overcome the traveling valve load of 2600 psi.

These figures explained several things at once. For instance if the pump intake pressure is lowered to 13-14 psi the compressive pressure in this pump drops to 831 psi. That is why the pump gas locked when I bled the casing pressure off. It also explains some of the troubles I have witnessed when separator pressures were reduced in primary fields in an attempt to increase production. (Figure 2)

By "tagging" the pump the operators are causing greater compression in the pump. It will often be just enough to break a gas lock. However, it is often the case that it is not enough to keep the gas lock from reoccurring.

Although I have not dealt with any of the "gas scavenger" devices that are being sold to lower casing pressure at the well head, I would suggest that gas locking could be a side effect of their use.

During my inquiry I found that it is common practice at pump shops to use a standard seat plug and cut the valve rod such that there is a plunger to end of barrel distance of about 1.5 inches. This practice translates into an unswept volume of about 7.5 cu. inches. The graph (Figure 1) shows the compressive pressure generated by these pumps at different stroke lengths. At a depth of 3000 feet one could expect a traveling valve load as high as 1350 psi. From the graph you can see that a length of stroke of 120" or more would be required to pump out a gas lock with these pumps at that depth.

At a depth of 6000 feet a traveling valve load of 2700 psi is possible. To obtain the required pressure with these pumps the stroke length would have to be raised to 240 inches. That is far from practical. The alternative is to reduce the unswept area in the pump. The graph (Figure 3) shows the effect of reducing unswept area in a pump with a plunger travel of 100 inches. Reducing the unswept volume to 3 cu. inches or less will generate the required compressive force.

This proved to be easier said than done. I contacted three of the major pump manufacturers directly and found that they did not make, nor were they planning to make standing valve cages with lower volumes. With average volumes of around 3.5 cu. inches (in the 1.5 cages) and about .5 in the hex type seat plug, for a total of 4 cu. inches it seemed that we were as far as we could go. However, as the graph (Figure 3) demonstrates, lower volumes are very desirable.

I again contacted my friends at Axelson in Kermit and they took an off the shelf standing valve cage to a local machine shop and trimmed one full inch off it's length and rethreaded it. This reduced the unswept volume in the cage area by about .75 cu. inches. Giving an unswept volume of about 3.25. We ran that cage in a well in which we are forced to pump from above the perforations (at 6400 feet with 120 inch stroke) and it has performed admirably for the last 8 months.

Even lower volumes are desirable though, for I have numerous wells which are pumping from between 5000 and 6000 feet that have pumping units with only 54 inches of total stroke length. Compression ratios of 50 or 60 to 1 are needed. To obtain that, the unswept volume must be less than 1.5 cu. inches.

I wrote an article on this subject that appeared in the June 1992 issue of World Oil. Shortly after it appeared an inventor cum salesman cum machinist came into our office peddling a device which eliminates gas lock altogether. My production foreman laughed him out of the office with instructions to read the article. He did.

In July of 1992 he approached me with a solution that was so elegant that I had to buy it even though the price was high. His name is Milton Skillman. He does business out of Mount Vernon Texas.

Milton built a traveling valve cage that eliminated the need for a seat plug. The seat and ball drop in from the top, a small guide is used to lock the seat in place when threaded onto the plunger. Total unswept volume is estimated at .25 cu. inches or less for the traveling valve. For the standing valve Milton built a cage that can be inserted into the barrel itself. It almost defies description. Total unswept volume for this setup is beyond my meager means of measurement but it is estimated to be less than 2.0 cu. inches. Milton assures me that better designs are forthcoming. He calls it a high compression cage setup. I ran this design into a 54 inch L.S. well and have had no trouble in the last 5 months.

Using his insight, my friends at Axelson in Kermit cooked up a design that uses off the shelf parts with the addition of only one locally machined part. It also uses the (inside the barrel) standing valve design and adds only $40 to the price of outfitting the pump. Estimated volume for this setup is about 2.5 cu inches.

They call this the "Inverted Standing Valve". We have run several of these lately and have had no problems directly associated with the design.

Recently I was called upon by the drilling department to evaluate a new well in which one of these pumps had been installed (2 1/2 x 1 3/4 x 26 ft. with hex type seat plug and "inverted" standing valve). It was suggested that it might be gas locked. I agreed that it was not pumping but stated that it was not gas locked because that would be impossible with that pump setup. I was met with incredulous stares.

Over the years I have shot fluid levels on many wells. A number of them seem to have fluid levels that are higher than they should be. Increasing pumping time has little effect on the fluid level. The reason this is true, I believe, is that the pumps in these wells lack enough compressive force to lower the fluid level below a certain point. The high fluid level provides enough pump intake pressure to generate the required compressive force in some of these wells.

A lease operator once told me that the best way to break a gas lock was to close the casing valves. He probably did not understand why it worked, he just knew that it did. In actuality he was raising the intake pressure on the pump, increasing its compressive force to the point at which the gas could overcome the traveling valve load (Figure 2).

To sum up, there are three ways to overcome a gas lock with compression techniques.

(1) Increase the stroke length. Raising the compression ratio by increasing the swept volume will increase the output pressure. Limitations in pumping units often make this impractical.(Figure 1)

(2) Increase the casing pressure. The suction pressure of the compressor relates directly to the output pressure. The increased pressure on the producing formation will often decrease production.(Figure 2)

(3) Reduce the unswept volume in the pump. The use of hex type seat plugs, pull rods cut to maximum length, and perhaps redesigning the standing valve cage can all but eliminate gas lock problems with a minimum expenditure.(Figure 3)

ACKNOWLEDGMENTS

Mr. Bob Gault- For putting me on the right track.

Mr. Fred Reynolds (Production Supervisor)- For allowing these new ideas to be tried in the field.

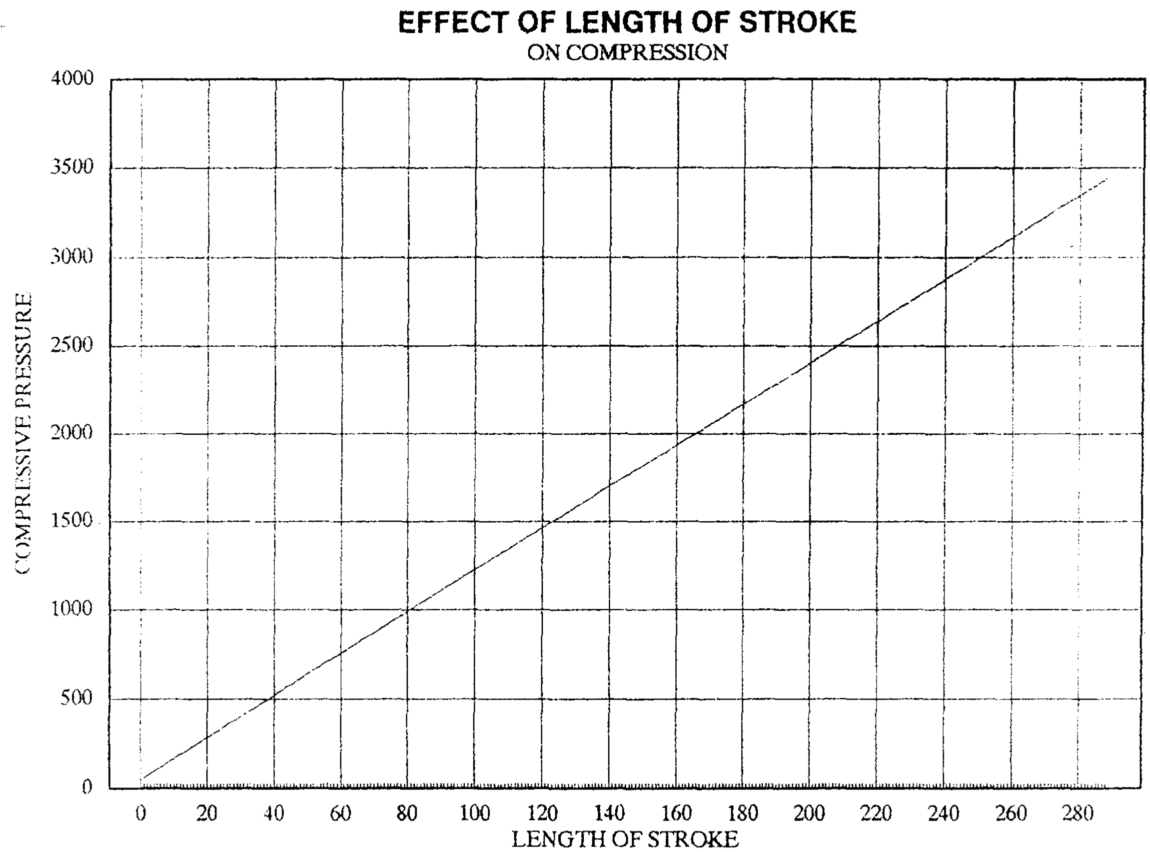

Figure 1 - Assumes USV of 7.5 cu. in.
& 1.5 bore pump

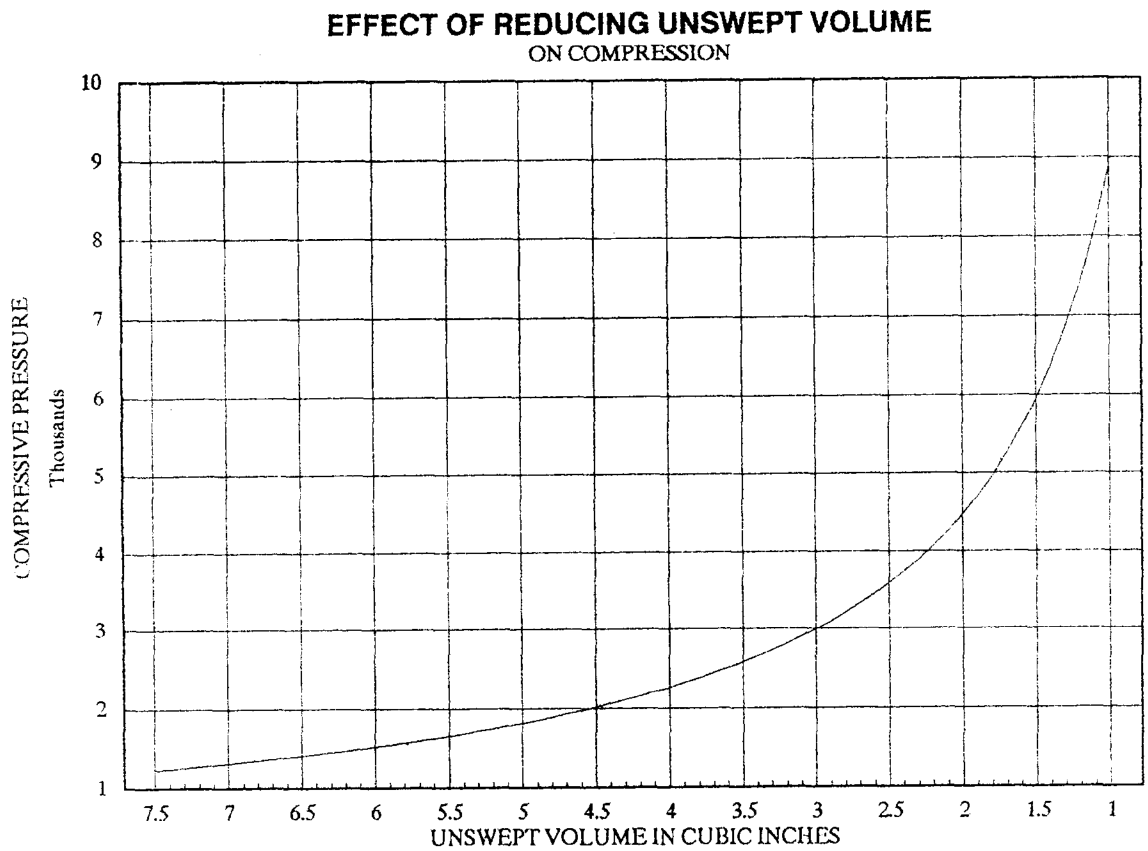

Figure 2 - Assumes 7.5 cu. inch USV & 100 in. stroke

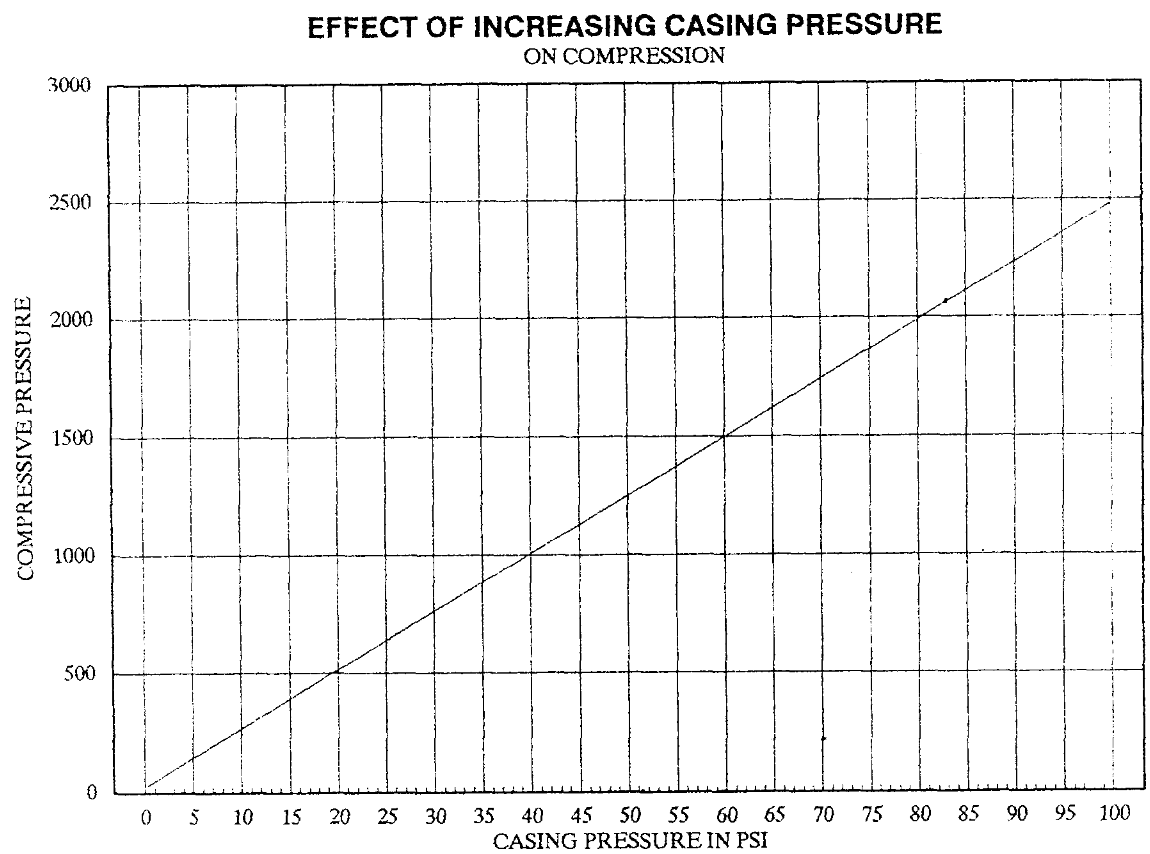

Figure 3 - Assumes 50 PSI intake and 100 in. stroke