THE PANACEA PUMP TOOL

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ABSTRACT

Gas interference and sand production are two of the biggest challenges for operators of sucker-rod pumped wells in southeast New Mexico's Delaware Basin. This paper will discuss the re-application of an old sucker-rod pump tool that solves both of these problems. The Panacea Pump Tool, which can be installed on any rod pump with a pin threaded barrel, consists of a hollowed out rod-pump extension coupling. A cavity created by the tool maintains a minimum liquid level in the pump barrel, which reduces gas interference and breaks gas lock. The cavity also provides continual cleaning of particle buildup from iron sulfide and sand that can wear on a pump's plunger, similar to stroke through pump designs. Pump off control has been critical to the resurrection of this technology. Numerous, repeatable successes in some of Texaco's toughest producing environments have made the Panacea Pump Tool the pump upgrade of choice.

GAS LOCK BACKGROUND

At the fortieth SWPSC (and in a similar article in World Oil) I presented a paper that dealt exclusively with compressive factors in pumps. At that time it was noted that unswept volumes of less than 2-½ times the pump bore were difficult to obtain using conventional balls and seats. Reducing the unswept volume to less than 2-½ times the pump bore requires the use of low volume cages, restricting the pump intake, or discarding the balls in favor of flat valves. Neither of these options is attractive.

Another method of increasing the compression of a sucker rod pump is to increase its net plunger travel. The calculated net plunger travel for a 640-305-168 pumping unit pulling a 1-½" bore pump at depths of 7,000 - 9,000 ft. is between 120 and 134 inches. Given an unswept volume of 2-½ times the pump bore, compression ratios of 76 in the 1-¾" bore pump, 64 in the 1-½" bore pump and 54 in the 1-¼" bore pump are expected.

Assuming that operators strive to keep pump intake pressures as low as possible to maximize productivity, then the compression of a high compression pump at 50 psi intake pressure and 168 inch surface stroke would be about 3200 psi. The fluid gradient in the tubing varies greatly from well to well, but if the gradient of fresh water is assumed as a baseline then it becomes apparent that compression alone cannot be a dependable method of defeating gas lock in pumps with less than 134 inches of net plunger travel below 7200 feet.

Calculated plunger travel varies with pumping speed, pump bore size, well depth, tubing gradient, and rod design such that accurate calculations of exact compression ratios are left to the operator of an individual well. If we assume that net plunger travel is generally 80% of surface stroke (less in very deep wells and more in shallow wells) then a depth barrier is created that, when crossed, one could not expect high pump compression to break a gas locked condition for that installation.

The most effective deterrent to gas lock is, and has been to place the pump intake below the well's perforations. Allowing the fluid and gas to separate as they enter the wellbore is a proven strategy. If complete separation does not occur at or slightly below the bottom perforation in the casing, then any additional depth added to the seating nipple only adds stresses to the pumping system rather than decreasing the likelihood of gas lock.

In the 1980's Gibson and Swaim outlined strategies for separating gas from produced fluid. The method involves allowing free gas to evolve from produced fluid by giving it time to rise out of the fluid before it enters the pump intake. The method also requires that the "dip tube" is of sufficient length that the intake stays immersed in fluid when the pump fills, preventing the entry of gas into the dip tube. Lengthening the dip tube beyond the minimum required to keep the intake submerged is counter productive because increased fluid friction in the dip tube adds to the pressure drop between the wellbore and the pump, increasing the gas lock tendency rather than reducing it. To that end, Texaco's Hobbs Operating Unit utilizes a dip tube chart that allows the pump supplier to quickly select the proper tube length for the application.

In deeper reservoirs and in situations where high fluid levels are present, gas tends to remain in solution. This inclination makes the strategies mentioned above less effective than they are in shallower wells, causing gas to be presented to the pump intake. If small amounts of solution gas are introduced to the pump and large pressure drops across the pump intake can be avoided, then the usual result is that the pump pumps normally but with a reduced efficiency. If large quantities of gas are introduced to the pump a gas locked condition can result.

GAS LOCK : THE CURRENT STATE OF THE ART

An observation can be made from the assumption that pumping units with longer stroke lengths are more desirable. Longer stroking units require gearboxes with a higher torque rating, making them larger and more expensive. In some cases moving large pumping units to problem wells will produce the desired benefit. This can be an expensive thing to do with large units and marginal well economics may prohibit any action to increase pump compression by installing a longer stroking unit.

For high compression pumps to be effective the pump spacing must be designed such that the pump is completely closed on the down stroke. This often leads to operators "tagging" the pump, with it's associated destructive force and the need for frequent re-spacing as the well's fluid level is lowered. Initial accurate spacing by the pulling unit crew is essential in this model and in an effort to facilitate this I wrote a small software program that calculates a starting spacing point. It is available for free downloading, along with other useful tools at www.cavemen.net/als.

Certain modifications to the pump itself, such as the "jet sub", attempt to port the barrel itself allowing a small amount of fluid from the tubing string to pass into the lower chamber preventing gas lock from occurring. This concept is effective but the volume of fluid allowed to continually circulate around the pump is subject to change with pressure (depth) differences and the reduction in pump efficiency can be difficult to accept. Additionally, the port often becomes plugged or fluid cut in a short time so that no real benefit is realized.

Other pump modifications attempt to act directly on the traveling valve to forcing it off its seat during, or at the bottom of, the down stroke. The intent being that the differential pressures across the seat would cause the gas to swap places with fluid on top of the plunger. In practice, it is often found that the compressed gas pressure and traveling valve load are very near equal when the pump compresses and therefore no exchange of fluid occurs.

SAND PRODUCTION BACKGROUND

Sand production with sucker rod pumps has always been a problem and is best discussed if the sands are broken into two classifications. The larger grains are usually associated with frac sands. The smaller grained or "flour sands" generally come from the formation.

The only pumping technique that is effective for both solution gas and sand problems is reducing the production rate. This gives the free gas an opportunity to rise out of the produced fluid and the sand a chance to settle to the bottom of the wellbore. The old oil field proverb that "sand floats" is simply not true. The cause of excessive amounts of sand being drawn through the pump is that the fluid in the wellbore is moving into the pump at such a high rate that the sand is not allowed sufficient settling time to separate from the fluid.

Separation of the larger sand grains can be achieved by lowering the fluid velocity and allowing the produced sand to separate. Large diameter mud anchors accomplish sand separation with relative ease. The use of a valve on the bottom of the mud anchor will prevent sand from filling the mud anchor.

Metal screens placed across the mud anchor inlet have been touted as an effective sand fighting technique. While the screens look as if they'd work on the surface, downhole it's a different story. The screen attached to the outside of the mud anchor is usually not guarded in such a way that the operator can be sure that it remains in place while sliding through a mile or more of casing. If it does remain in place, the usual result is that the first time the pump is unseated with a tubing string full of fluid the screen is washed away by the tremendous force generated by the hydrostatic load flowing back through the mud anchor ports.

Filtration systems of various types can stop the larger sand grains from entering the pump. They also have the effect of increasing the pressure drop between the well bore and the pump, which can lead to more frequent gas locking as previously discussed. When using filters in a gassy environment allowances must be made for the filter to stay fully immersed in the fluid of the mud anchor. This can cause the required mud anchor'length increase dramatically.

Other devices offer to separate sand from fluid by creating centrifugal force in the fluid. The idea being that the sand can be "spun" out. This technique might work for large sand grains that have sufficient mass, but the spinning action may cause gas interference problems. Any agitation to a solution gas mixture causes gas to break out where it can be introduced to the pump intake.

The best method for dealing with frac sands is at the point of introduction to the well bore. "Resin Coated Sand" has been the most effective method of reducing frac sand production to date. The increased cost of a RCS frac job can be more than offset by the cost of replacing pumps and cleaning sand out of the well bore in a year's time.

The "flour" or formation sands are much harder to deal with than frac sands. Filtration methods that stop fine sands from entering the pump must have a very fine mesh that is so restrictive that it stops fluid from entering the pump also. Screens and centrifugal devices have no demonstrable affect on fluid mixed with fine-grained sands other than increasing the propensity for gas breakout at the pump intake.

In the end the operator must find a way to lift the "flour" sand with the pump and deal with it on the surface.

PUMP DESIGNS FOR "FLOUR" SAND PRODUCTION

Improvements to materials used for balls and seats have dramatically increased the life of these pump components in sandy environments. In prior years the failure of the balls or seats or both was the expected root cause of any pump operating in a flour sand environment. New materials have greatly reduced the incidence of failures in which the ball returns to the surface in a dull, rough condition.

Today, a more likely failure in these conditions is plunger wear. The plunger traps sand between itself and the barrel and wears down to a point that the fit opens the pump sealing surfaces to a large amount of slippage. Although technically not a failure, since the pump still moves fluid, the pump's efficiency drops and continues to drop until a production **loss** is incurred. Sand adheres to the metal parts in the pump as if magnetized and can only be removed in the pump shop through vigorous wiping and washing of the parts.

All manner **of** plunger styles and types have been invented and marketed specifically to reduce the wear imparted on them by flour sands. These plungers can be divided in to two groups, hard plungers and soft plungers. Hard plungers are of standard smooth design with all variances in length and fit. Some of these plungers have been designed with grooves of varying thickness and depth that **do** not have any sealing rings in them. The soft plungers are also grooved but are designed to accept some type of soft sealing ring.

In the hard plunger category no really effective designs have surfaced. None of the designs have proven more effective than another at reducing the wear imparted by the sand. Eventually the plunger will become worn to the point that excessive slippage requires that the pump be replaced.

The soft plunger classification contains a number of plungers that have various types and numbers of rings made of some type of synthetic material. These have proven no more effective than the hard plungers, in most cases. The sand eventually abrades the sealing rings and the pump begins to slip just as if a hard plunger was run. Some operators claim longer runs with these plungers, but my experiences do not support **this** result.

One of the most effective pumps at dealing with the flour sands is the "san pump". **This** design simply reverses the traditional pump configuration such that it has a very long plunger and a very short sealing barrel. It seems that the expanded chambers above and below the sealing barrel allow enough fluid movement to wash the flour sand off the plunger and keep it from being drawn into the sealing area where the abrasion occurs. One problem with this pump design is that it has an extremely low compression ratio, so when it gas locks there is no easy remedy.

A modification to this design that increases the compression ratio and appears to work in many wells where the "san pump" may not, normalizes the plunger length and adds barrel extensions to the sealing barrel. This usually entails a ***2*** or **3** foot extension on the bottom of the sealing barrel. The extension on the top of the sealing barrel is at least one foot shorter than the plunger. This keeps the plunger from exiting the sealing barrel on the upstroke.

This design is usually referred to as a "stroke through" pump and has been fairly successful at pumping sandy wells and wells that produce quantities of iron sulfide. It allows the top and bottom of the plunger to be "wiped" on each stroke, reducing the amount of abrasive material that builds up between the plunger and the sealing barrel. It also reduces available compression and therefore has a tendency to gas lock.

So it seems that an impasse has developed. A pump designed to reduce gas interference will fail in a sandy environment and a pump that will reduce sand problems will lead to frequent gas lock conditions. Until recently, an operator's strategy was to attack the more significant problem and then suffer under the lesser of two evils.

THE TRIPLE ACTION PUMP

As installation of the triple action pump approached, the team members met and discussed the fact that, as it was designed, the pump would be highly susceptible to gas lock. Most of our concerns centered on the likelihood of gas lock in the upper pump chamber. The differentially acting upper pumps would generate almost zero compression and the only likely way to break a gas lock would be *to* unseat the pump. Additionally, if the upper pumps stopped lifting fluid, the injection plunger would continue to inject fluid into the disposal zone and eventually start injecting oil as the well pumped off. Much discussion and planning centered on the possibility of that happening. In truth, it never occurred.. .

What did occur, was that a pocket of gas began to develop in the pumping chamber of the lower "injection" pump. It appeared to grow slowly and began to absorb part of the injection pump's displacement. As the efficiency of the injection pump declined, the team started to discuss ideas for preventing the occurrence in the future. I suggested that we groove the injection plunger such that when it passed through the sealing barrel on the upstroke that a small amount of the trapped gas would be drawn out by the grooves. This would not reduce the injection efficiency, would be easy to do, and would transfer a controlled amount of gas from the injection chamber to the lower pressured chamber above it. The solution worked well and sparked an interest in the team to apply the technique to conventional sucker rod pumps.

THE PANACEA

As a direct result of the team's work on the Triple Action Pumping System, Brock Watson had the first device built that would later become the Panacea Pump Tool. When it was first presented to me, I was not impressed. After some thought and a little salesmanship by Jonathan Dimock I agreed to give this new idea a **try.** As you may suspect, I saw the tool's excellent results first hand and quickly became a strong believer. The new tool inverts the practice of "bailing" gas out of the lower chamber of the Triple Action Pump, in order to apply the same technique to conventional sucker rod pumps. The tool basically consists of a lengthened barrel coupling. The coupling has a larger inside diameter than the barrel it **is** attached to, making it similar to an extension coupling on a "stroke through" pump except that this extension is placed in the middle of the pump's barrel. Tools made from carbon steel have worked well, but they can be nickel plated for additional corrosion resistance.

No other modifications to the pump are necessary. In a gassy situation, the tool allows a small amount of gas to be transferred to the upper side of the plunger when it passes the tool on the down stroke. It allows a small amount of fluid to be transferred to a position below the plunger on the upstroke. When a gas lock occurs, depending on a number of factors discussed before, the pump will run a number of strokes and then suddenly start pumping as the gas locked condition is broken.

In a sandy situation the fluid in the chamber will continuously wipe the entire length of the plunger. The plunger passes completely past the tool in both directions without losing contact with the sealing surfaces. This allows the fluid in the tool to be completely replaced on each stroke. This replacement reduces the likelihood of sand building up either on the tool or the plunger.

DESIGN CONSIDERATIONS

The Panacea pump design begins with the downhole stroke length. Downhole stroke length determines both the length of the plunger and the length of the bottom barrel. The plunger and bottom barrel lengths must be derived from the downhole stroke length in parallel calculations. In other words one does not determine the other, and the solution is a "best fit". They must be short enough, in relation to the downhole stroke length, that the plunger passes completely through the coupling on both the up and down strokes. Once the lower plunger-barrel combination is determined, all that is left is to ensure that the upper barrel is long enough to prevent tagging on the upstroke.

INSTALLATION CONSIDERATIONS

When the pump is installed it must be spaced such that the plunger passes completely through the coupling. I suggest using the top of the pump as a guide such that when the pump is felt to "tag" whkn it is pumping, the rods should be raised one inch at a time until the pump stops tagging. Then if the design was correct the tool will be able to do its work. On two occasions I have had to lower the rods on a Panacea pump that quit pumping. In each case the spacing was such that the plunger was not fully clearing the coupling on the down stroke.

When running the Panacea pump on a rod pump controller it is beneficial to modify the controller program such that the span fault is used to start and stop the controller for it's normal down cycle. If span is set to render the well off then the Panacea will not have a chance to relieve the gas lock condition. The number of low load span strokes allowed before shutdown should number between 10 and 15, or more depending on the well. Allowing the pump to stroke several times before LLS shut down gives the Panacea Pump Tool several strokes to alleviate gas interference or gas locked conditions.

In determining the pumped off condition this pump is the same as any conventional pump and the operators usual settings should be adequate. A dynamometer analysis of the pump will show no difference with the Panacea tool installed. Conventional operation techniques are suitable for this design.

SUMMARY

The Panacea tool has shown itself to be effective at relieving gas locked conditions in a variety of rod pumped wells at depths ranging from 4,500 ft to 10,000 ft plus, with surface stroke lengths from 36 inches to 168 inches. It has extended the run lives of both plungers and barrels in Texaco's Delaware Basin wells. The tool has been successfully run in both new wells and following major workovers, where other pump styles have not given good service in the past. The Panacea Pump Tool is known outside of Texaco as the Gas Bailer tool.

panacea n. [L. < Gr. < pan, all + akeisthai, to cure] a supposed remedy or cure for all diseases or ills: cure all

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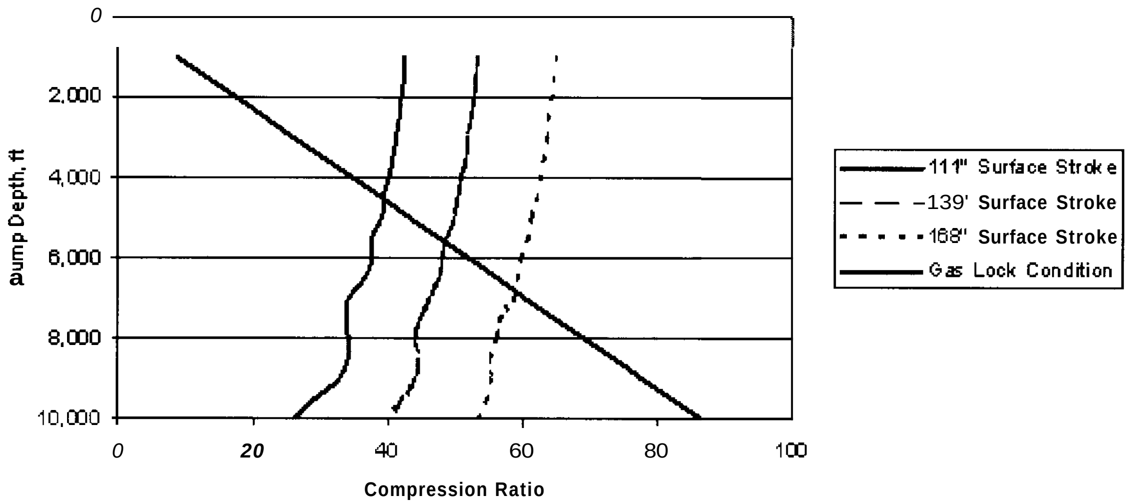
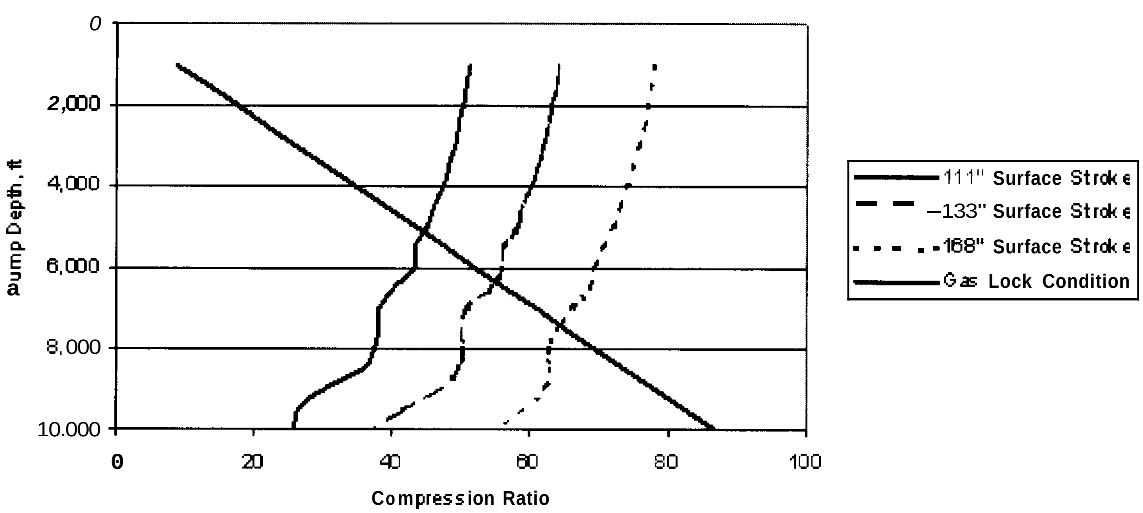
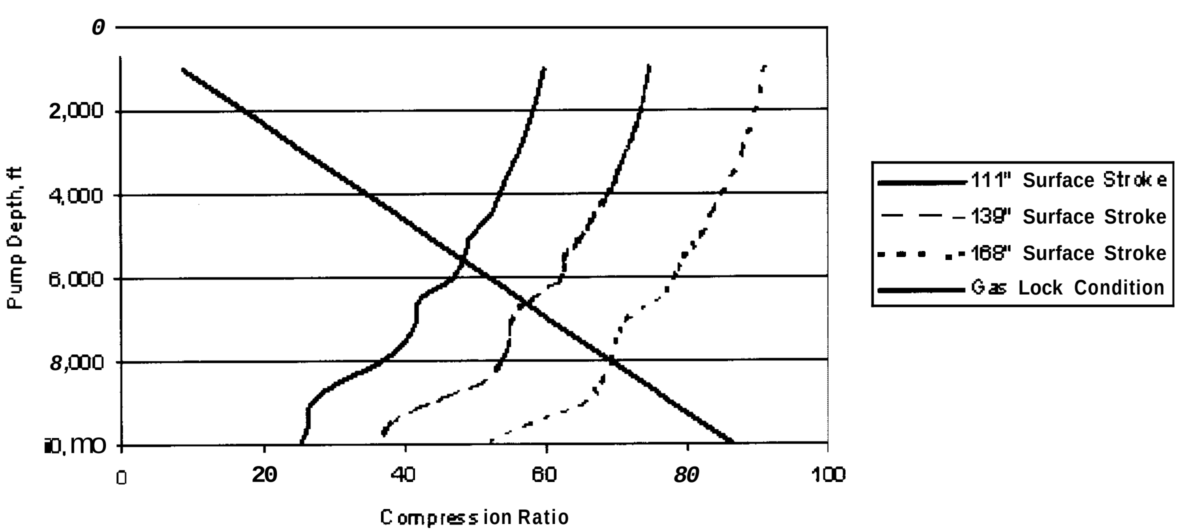
Operational Limits of 1-1/4" High Conpression Pumps

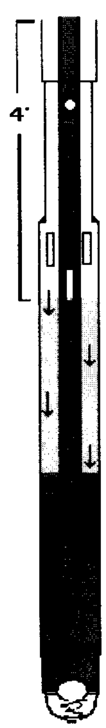


Operationd Limits of 1-1/2" High Cornpression Punps

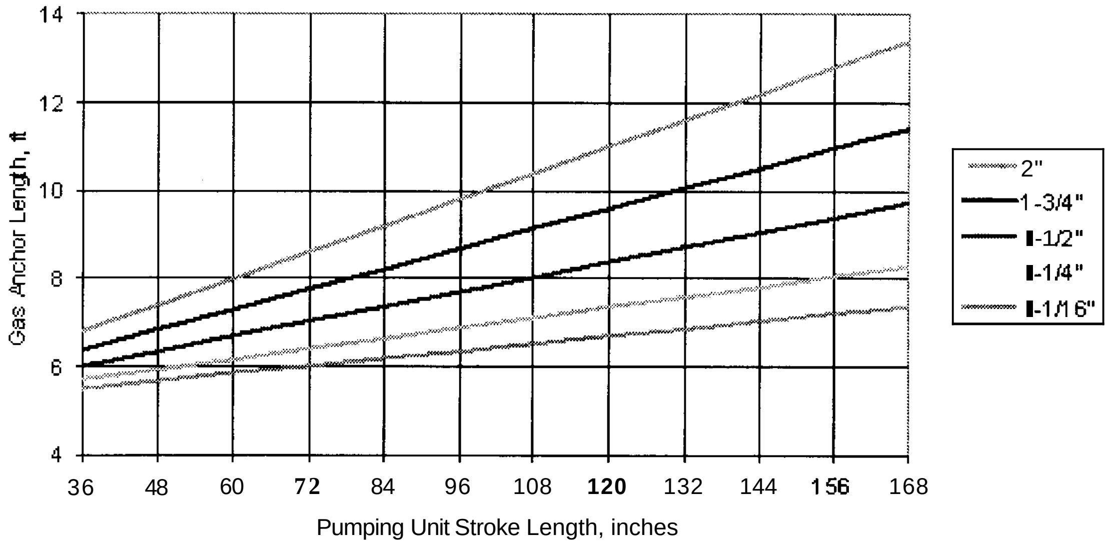


Operational Limits of 1-3/4" High Compression Pumps





3-1/2" O.D. Mud Anchor with 4' from SN to Bottom of Lower Slot



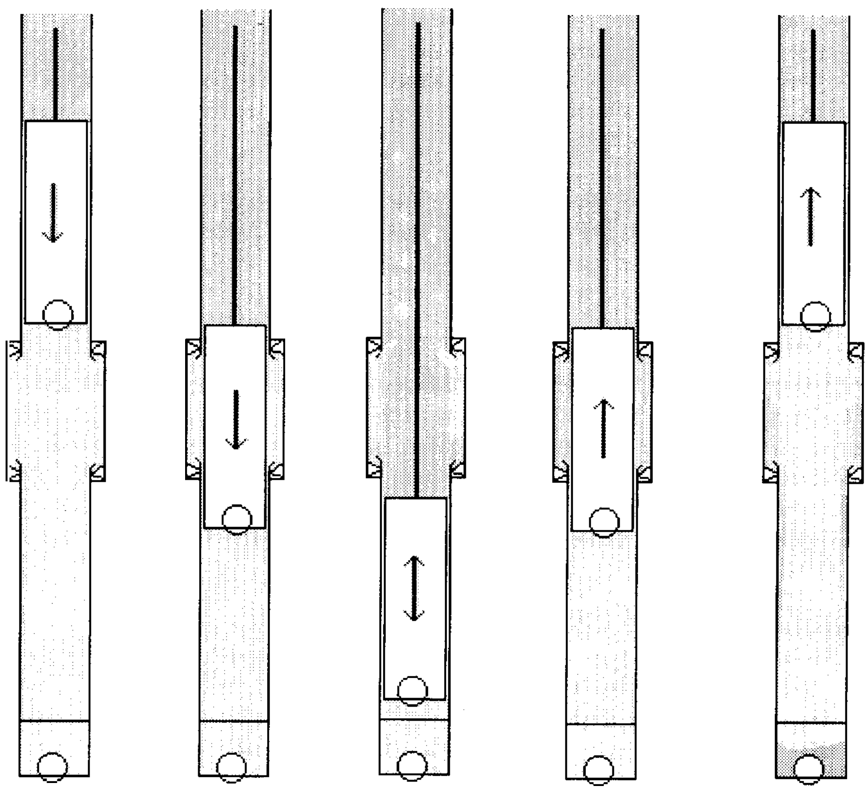


Fig. 1 Fig 2 Fig. 3 Fig. 4 Fig. 5