Introduction to Plunger Lift: Application, Advantages and Limitations

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ABSTRACT

This paper discusses the principal of plunger lift and it's possible applications. Typical applications are:

1. Removal of Liquids from Gas Wells
2. Hi-Ratio Oil Well Production
3. Paraffin and Hydrate Control
4. Increased Efficiency of Intermittent Gas Lift Wells

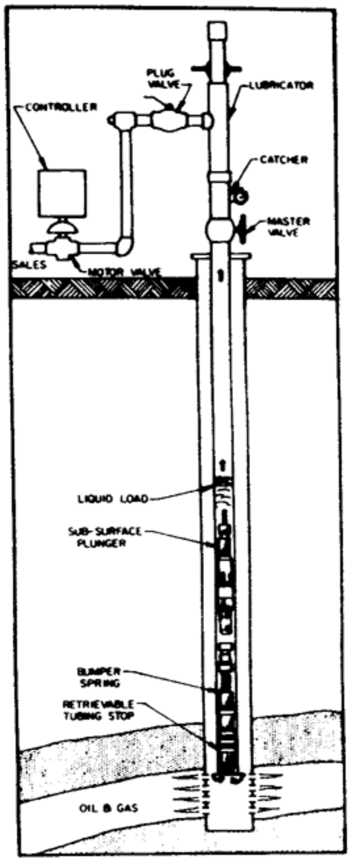
Some advantages of this system are low initial cost, very little maintenance and that there is no external source of energy required in most cases. Limitations such as mechanical conditions, gas and liquid volumes and depths are also discussed. There will be a brief section concerning the various types of equipment available.

INTRODUCTION

The principle of the plunger is basically the use of a free piston acting as a mechanical interface between the formation gas and the produced liquids, greatly increasing the well's lifting efficiency.

The successful operation of these systems is predicated on the assumption that the wells have no packer or have communication between the tubing and the casing at the bottom of the production string. The purpose of this paper is to describe the applications of this system to certain production problems.

A typical installation consists of a stop and spring set at the bottom of the tubing string and a lubricator and catcher on the surface acting as a shock absorber at the upper end of the plunger's travel. The plunger runs the full length of the tubing between the stop and lubricator. The system is completed with the addition of a controller (time and/or pressure) and motor valve with the ability to open or close the flowline. (see Figure 1).



Typical plunger installation.
FIG. 1

Figure 1

Operation of the system is initiated by closing in the flowline and allowing formation gas to accumulate in the casing annulus through natural separation. The annulus acts primarily as a reservoir for storage of this gas.

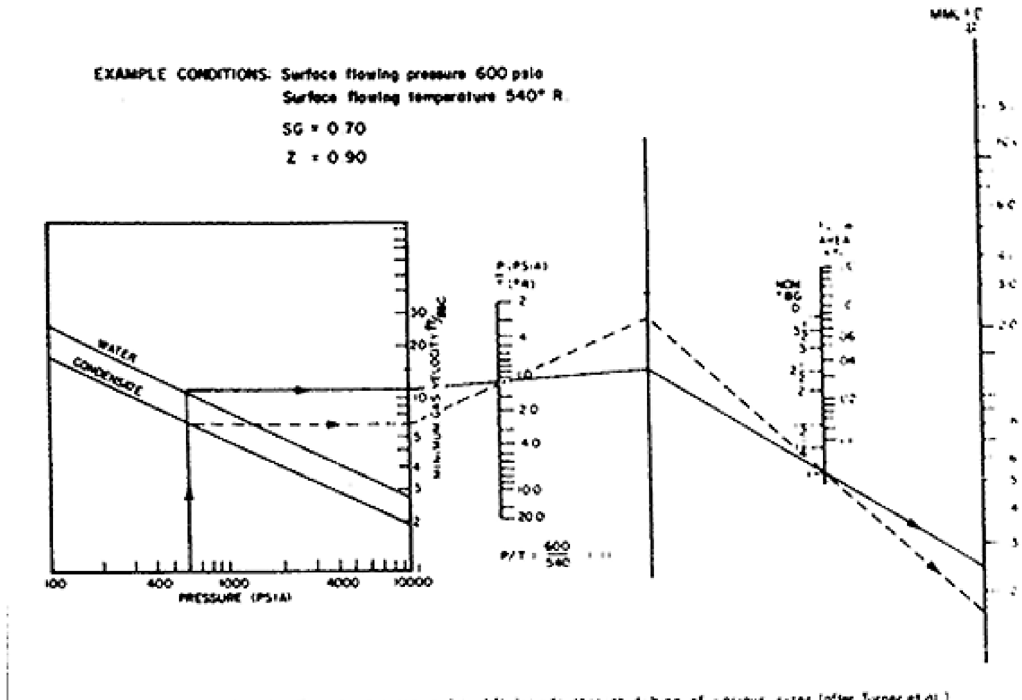
After pressure builds up in the casing to a certain value, the flowline is opened. The rapid transfer of gas from the casing to the tubing in addition to gas from the formation creates a high instantaneous velocity that causes a pressure drop across the plunger and the liquid. The plunger then moves upward with all of the liquids in the tubing above it. Without this mechanical interface, only a portion of the liquids would have been recovered.

APPLICATION

Removal of Liquids from Gas Wells

Almost all gas wells at some time during their flowing life are subject to producing liquids. As long as the conditions are such that wells are able to sustain a sufficient velocity in the tubing, liquids are carried out with the gas as multiphase flow.

Below a certain "critical velocity", liquids tend to migrate down the tubing and start to collect at the bottom. Turner, et.al,[1] shows that this critical velocity is a function of flowing wellhead pressure, type of liquid (water, condensate, etc.) temperature and conduit size. (see Figure 2).



Nomograph for calculating gas rate required to lift liquids through tubing of various sizes (after Turner et al.)

FIGURE 2

Figure 2

For a while the well is able to unload the small slugs on it's own. The surface indications are "heading" recorded on the sales chart. If no remedial measures are taken, the problem will worsen until the well loads up and dies.

Other indications of liquid loading problems are sharply decreasing production decline curves for both gas and liquids. Any well that must be "blown down" periodically is most certainly experiencing liquid loading.

The function of the plunger is to prevent these liquids from accumulating to the point that the well would die or require a lengthy shut-in period to recover.

The well is shut in when it is determined that loading is indeed occurring down hole. The well is opened up when casing pressure has built up enough to lift the accumulated liquids in the tubing along with the plunger as the gas breaks around the end of the tubing. This pressure and velocity must be great enough to overcome the sales line or separator pressure encountered on the trip to the surface.

Upon arrival of the plunger at the surface, the tubing string is completely free of liquids. At this point the formation encounters the least resistance to flow. Depending on the productivity of the well, high flow rates may be sustained by leaving the flow line open for some increment of time. This increment may be dictated by a certain pressure drop on the casing or observation of the sales chart to determine a time interval. The well should be shut in when loading is evidenced by a decline in differential on the sales meter. Then the cycle should be repeated.

Plungers are very effective even on low-pressure gas wells that have good productivity. It is necessary to cycle the plunger frequently removing very small amounts of liquids at a time. The good deliverability assures prompt recovery of casing pressure for the next cycle.

An increase in production can be expected from utilization of this system. The real benefit shows up in cumulative production and resumption of a normal decline curve.

Hi-Ratio Oil Wells

When considering a plunger application for an oil well, it is easy to extend the concept of "unloading a gas well", to producing a high ratio oil well. In many cases the wells are practically the same. Only the mechanics of operation change.

Again, the motivating energy for all plunger installations is gas. With high gas liquid ratios it is easy to have a plunger run up and down the tubing whether it's in an oil well or gas well. The difference is the need for the end product. Is the installation designed to produce oil or sell gas?

Reservoir characteristics will have a determining factor on the mechanical equipment to be used in producing a hi-ratio oil well. The two most prominent applications are for wells with a low bottom hole pressure but with high productivity and the other is a high bottom hole pressure with low productivity. The type of reservoir drive, whether it is "solution gas" or "expanding gas cap" will have some effect on the longevity of the installation but not the mechanics.

The low bottom hole pressure well will quit flowing continuously when it can no longer sustain the velocities in the tubing to bring its liquids to the surface. It can be qualified as a good gas producer. The first indication of a loading problem will be erratic production normally seen on the gas sales meter. The fluid will be produced in small heads with spikes of gas on the sales chart. Though the well does not produce continuously, the heading is uniform.

A plunger installation for this type of well should be cycled as often as possible. It should have a fast fall time and be produced into the production facilities at a high rate. Operation of this type may produce only fractions of a barrel per trip, but since we have qualified the well as highly productive, the well will recover quickly for another cycle. The surface lubricator should include a shut-off on arrival mechanism to minimize the flow period after the tool arrives at the surface. The shut-in period can be determined by time cycle or casing pressure controls on the flow line.

Immediate results are usually noted with this type of installation. The amount of increase in both fluid and gas will depend on the IPR of the well. It is not uncommon for production to double. If the prolonged loaded condition has not saturated the well bore then the increase in production will hold. There are instances where the rate will decrease slightly, but the overall increase should be considerable.

High bottom hole pressure wells may have high ratios but unlike the low bottom hole pressure wells they are usually poor gas producers. The reservoir is normally tight and the gas sales meter will indicate very erratic flow. When fluid is produced it usually comes in large slugs and is not uniform in its unloading cycle.

The equipment for this application is almost the same as the former installation except for the plunger itself. Since the well will not recover rapidly the tool does not need to by-pass, as is the case for fast fall cycles. Operating pressures need to be higher since there is less gas and more fluid per cycle. Cycle frequency should be determined by casing pressure recovery. An arrival shut-off is imperative for the more marginal applications to minimize gas usage.

The results to be expected on this type of application are "consistent production". Any increases in total fluid should be compared on a monthly basis, not daily. The only assurance the plunger offers is the lowest average flowing bottom hole pressure possible through stopcock flow.

Paraffin and Hydrate Control

Many dollars are spent annually to remove build-ups of paraffin down hole. The primary expense is wireline costs but this is compounded by lost production due to reduction prior to cutting and down time while cutting.

Paraffin begins to form as a microscopic film below a temperature of approximately 100°F. It does not become a problem until the deposition becomes thicker due to accumulation over a period of time. This may be hastened by gas expansion in the tubing with its resultant cooling effect. Wells that have sufficient gas liquid ratios may utilize the plunger as a simple solution to the problem.

Installation of a stop and spring somewhere below the paraffin line facilitates the utilization of a plunger to "wipe" the tubing several times a day to prevent paraffin formation. Plungers do not "cut" paraffin, but when installed in clean tubing will prevent accumulation by virtue of a mechanical wiping action. The frequency of cycling will depend upon the severity of the problem.

Downhole formation of hydrates is another problem that has been successfully addressed by application of plungers. Hydrates are formed as a function of pressure and temperature. The higher the pressure, the higher the temperature at which the hydrates will form.

High-pressure gas wells are particularly prone to this problem. The problem is compounded if there is a fresh water zone down hole that creates a temperature anomaly. This cooling effect could cause hydrate formations that can block off all flow up the tubing.

The problem has been solved in many areas by the installation of a plunger in conjunction with a pneumatic chemical pump connected to the tubing at the surface. A typical cycle would synchronize injection of methanol or alcohol down the tubing when the flowline is shut-in and the plunger is falling. The methanol softens the hydrate plug so that the next cycle of the plunger removes any deposits.

This system may also be used in conjunction with the unloading of liquids from the gas well.

Increase Efficiency of Intermittent Gas Lift Wells

The problems encountered in deep intermittent gas lift wells are manifold. Well fluids are lifted from deep in the hole in the form of a "slug". The efficiency of the slug recovery is dependent on several factors. One, of course, is the size and length of the conduit in which it must travel. The wall of the tubing is exerting a certain amount of friction on the slug as it moves to the surface. This creates a drag on the outer perimeter of the slug as it moves to the surface. This creates a drag on the outer perimeter of the slug and it subsequently assumes a ballistic shape with gas underneath attempting to break through. But also, a wetting of the tubing string for each slug produced along with parts of the slug that lose velocity cause what is known as "fall back". The severity of the fall back is a function of slug velocity. This velocity is affected by gas lift injection pressure and surface backpressure. Depending on these variables, the lift efficiency may be from 60% to as low as 30%.

This problem manifests itself in higher flowing gradients in the tubing and higher flowing bottom hole pressures. This in turn reduces formation draw down and feed-in into the well bore.

Installation of a plunger directly above the operating valve offers several benefits. When the gas lift valve opens and gas is injected under the plunger, it begins to move upward with the slug of fluid above it. Since the pressure is greater below the plunger than above, there is virtually no slippage of fluids back down the hole. In fact, there will be a small amount of gas escaping upward around the perimeter of the plunger effecting a wiping action on the tubing wall. This prevention of fall back also helps to compensate for surface backpressure and restriction.

The efficiency of the lift now increases dramatically to almost 100%. The immediate benefits from this are a reduction in makeup gas and lower compression costs. Other benefits are reduced flowing gradients in the tubing, and lower flowing bottom hole pressures. The resultant increase in formation drawdown should allow liquids to feed into the well bore more rapidly. Increased frequency of well cycling should show an increase in production. An additional benefit is complete elimination of any paraffin or deposition problems.

LIMITATIONS

The applications we have discussed of course have limitations. In all cases we have stressed "lots of gas'. The required pressure and gas fluid ratio for a given depth and volume of fluid is shown on the graphs in (Figure 3 for 2 inch tubing or Figure 4 for 2 ½ inch tubing). These graphs are conservative in that they show a need for higher net pressure and GFR than is necessary for some plungers. However, if the well to be considered fits the graph then you can be assured of a good installation.

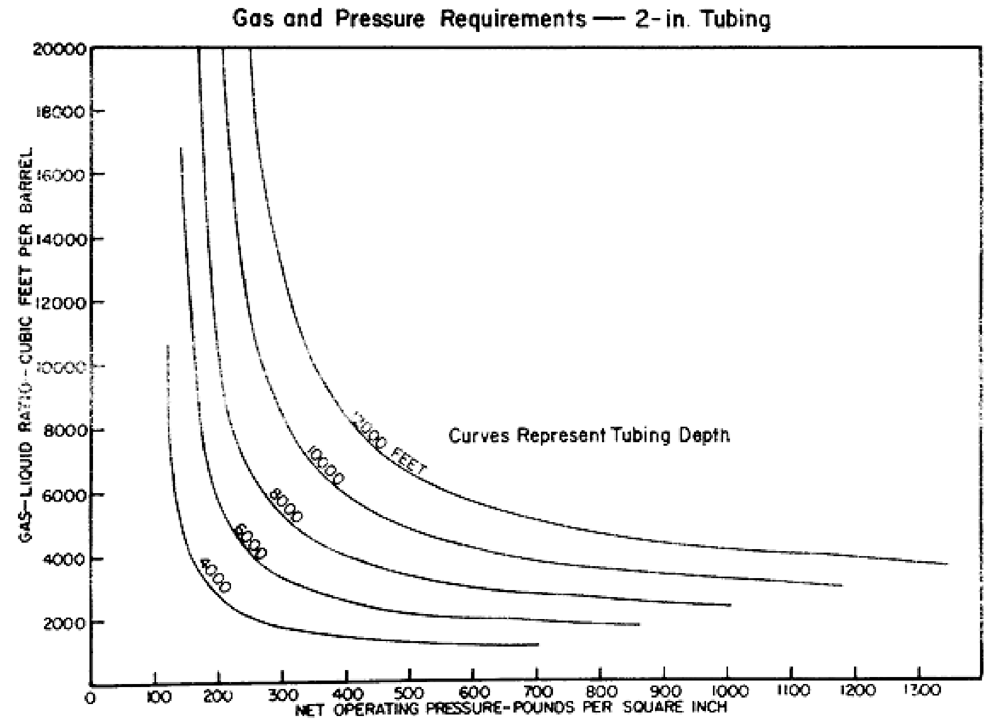


FIGURE 3 Continued on new page

Figure 3

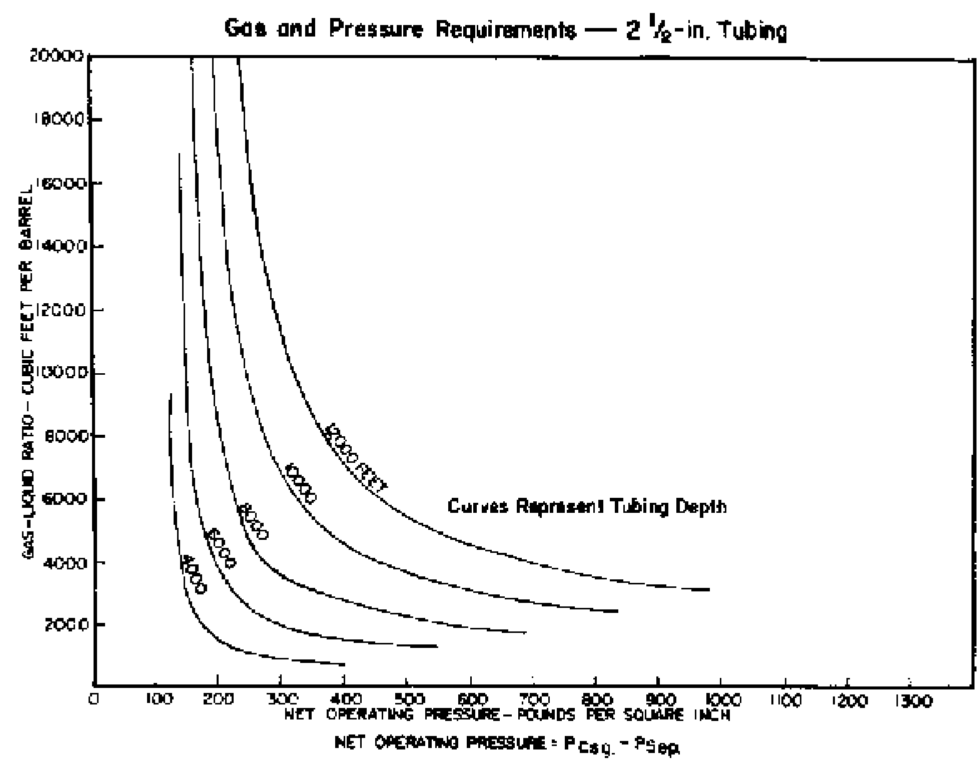


FIGURE 4

Figure 4

Another consideration should be the tubing condition and well head size. The tubing must be the same size from the hanger to the bottom of the string. A gauge ring run with a wireline unit will indicate any tight spots, which must be removed. The well head, including master valves and flow tee, must be the same size as the tubing and in case of multiple valves, stripped down to minimize the height of the tree.

When considering a plunger application it is most desirable to prepare the well for optimum operation as you would for any artificial lift system. Remove the packer and run the tubing with a pump seat nipple on the bottom and hang it open ended at the top of the perforations. At the same time the wellhead can be streamlined as discussed previously. Locating the tubing at the top of the perforations assures us of good natural separation and a minimum hydrostatic head from the perforations to the bottom of the tubing

Caution should be exercised when considering wells that produce sand. It may come from loose consolidated formations, or be frac sands. There are some instances where plunger have operated in the presence of sand but the operator is risking a stuck tool or damage to the production facilities.

TYPES OF PLUNGER EQUIPMENT

Controllers

There are three basic categories of controls that determine the cycling of the motor valve on the flowline.

1. **Time Cycle** - This controller is primarily a mechanical wind-up clock with a timing wheel and a pneumatic system. It responds to a set interval of time on the wheel to send or block a supply signal to a motor valve. Time determines frequency and duration of the on and off signal. Normally the only function is time, but some variations respond to other pneumatic accessories.

2. **Pressure Controller** - This controller opens and closes on a change in pressure. Normally for plunger application, the well opens when pressure has reached a certain high value in the casing and closes when the pressure is reduced to a pre-set low. This controller may also be influenced by other pneumatic signals such as shut-off on plunger arrival.

3. **Electronic Controller** - This new controller incorporates solid-state circuitry for timing and is powered by "D" cell batteries. The average life of the batteries is one year. Timing is only one function of the controller, however. The controller responds to many other external signals such as plunger arrival shut-off, Hi or Lo pressure, liquid level or differential. The signals are received electronically rather than pneumatically. These capabilities allow a wide range of applications and versatility.

Plungers

There are several types of plungers, which will be mentioned here. They all operate on the same basic principle. The variations are seal efficiency, weight and by-pass arrangement. Each plunger normally has some advantage in a given situation.

1. **Turbulent Seal** - This type is merely a series of grooves cut into a solid or hollow bar. It may or may not incorporate an internal valve mechanism depending on the manufacturer and application. The seal is affected by rapid movement of gas by these grooves. A vortex is formed within each groove and a pressure drop occurs causing movement of the plunger.

2. **Wobble Washer Type** - This model incorporates a series of rings or washers slightly less than drift diameter of the tubing. They are mounted on a mandrel and may or may not have an integral valve activated by a rod through the center of the mandrel. The seal is affected by the movement of gas by the specially shaped washers, which are held against the tubing wall by eccentric springs. This forms a turbulent seal similar to the model previously mentioned.

3. **Brush Type** - an unusual type of plunger utilizes a brush for the sealing element. This model is also available with or without the internal by-pass arrangement.

4. **Expanding Blade** - This model incorporates a series of spring-loaded blades that conform rather closely to the tubing internal diameter. Here again an internal valve may be incorporated, depending on the application and manufacturer. The valve may be shifted by an integral or external rod. The seal is affected by the relatively close tolerance of the blades to the walls of the tubing.

5. **Segmented Retractable Metal Pads** - This model incorporates a series of interlocking spring loaded steel pads that conform closely to the full I.D. of the tubing. The seal is affected by the close tolerance to tubing I.D. and radius as well as the interlocking of the pads. The by-pass is accomplished by the ability of the pads to retract and reduce the outside diameter of the tool. It is also available without the retractable feature, depending on the application.

Lubricators

The lubricator is installed directly on top of the tree or master valve. The primary function is to absorb the kinetic energy of the plunger at the upper end of its travel. It consists basically of a spring, bumper plat and a removable cap for inspection of the plunger. Usually incorporated in the lubricator assembly is a spring-loaded ball or cam type catcher to facilitate the above mentioned inspection.

Bottom Hole Assembly

The bottom hole assembly consists of a stop and spring. Its function is to provide a shock absorber at the lower end of the plunger travel. The combinations depend on the type of tubing and the mechanical hook-up of the well. The parts normally used are as follows:

1. **Collar Stop** - This device lands in the internal recess created by the joints of tubing at the collar. It is set and retrieved with a wireline.

2. **Tubing Stop** - This slip-type stop is utilized when it is necessary to land between collar recesses or if integral joint tubing is encountered.

3. **Standing Valve Cage -** This is a standard pump standing valve cage with a fishing neck attached for use with a wireline. It has a "no-go" ring, which lands, in a standard pump seating nipple.

4. **Bottom Hole Bumper Spring -** This spring lands on top of the stop or standing valve cage to act as a cushion for the plunger when it hits bottom. It will have a fishing neck on one end for retrieval. The other end may have a fishing neck or a collett for a hold down. It also may be combined with a standing valve cage for one trip retrieval of both parts.

CONCLUSION

The main advantage of using a plunger to produce a well is economics. First of all, an industry wide average installation will cost $3500 plus some service, which depends on the company furnishing the equipment. Compare this to a pumping unit to do the same job ($28,000) or a small compressor ($32,000). Secondly, there is no power consumption such as electricity (high initial cost to run to the lease) or gas consumed (at $2.40/mcf). All the energy is furnished by the well including instrument gas. Next consider the fact that many times the plunger will produce more product than any other form of lift. Last but not lease, is the low maintenance cost for such a system. Usually the only part that wears is the plunger. If it is inspected on a monthly basis, and wear is evidenced, it can be exchanged or repaired at minimal cost.

In summary, it can be said that plunger lift is a very economical and efficient production tool and should be considered along with other forms of artificial lift.

REFERENCES

1.Turner, R.G., Hubbard, M.G., and Dukler, A.E.: "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells", Journal of Petroleum Technology, November, 1969.

