INTERMITTENT GAS LIFT, PLUNGER-LIFT ASSISTED

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ABSTRACT

Many of the thousands of wells produced by intermittent gas-lift experience similar problems. One problem is that the system is attempting to lift a static slug from the bottom of the well to the surface, which is quite inefficient. As the slug moves toward the surface, there is a frictional drag on the liquid slug along the inner walls of the tubing. That drag, coupled with the fact that the gas is travelling faster than the liquid, means that there is a tendency for the gas to outrun the liquid. The liquid that is outrun never reaches the surface, it falls back to the bottom of the well. By creating a fluid column in the bottom of the well, this "fallback" increases the back pressure on the formation, thereby reducing the effective average flowing bottom hole pressure. The net result is less production.

Another common problem experienced in intermittent gas-lift is over-injection. In some operations the injection gas is intentionally over injected to help "sweep" out the falling liquid. While this could help, it is highly inefficient. On wells where the injection gas is controlled by a choke or orifice, over injecting in nearly impossible to avoid. Over injecting also keeps the tubing pressure of the well higher for a longer period of time. This has a negative effect on the flowing bottom hole pressure, and on liquid production.

This report will address these common problems, and offer a sensible solution to both. The applications for this system are widespread, but cannot be automatically applied to every gas-lift well. As with all other artificial lift systems, each well must be studied individually to determine it's suitability. Plunger-lift offers the producer options, but cannot be viewed as a cure-all.

GAS LIFT OPERATION

Intermittent gas lift is an operation whereby high pressure is injected into the casing annulus, and transferred into the production tubing of a well, via a "gas lift valve". This valve is typically operated on pressure or differential. It opens when a predetermined pressure is present in the tubing and in the casing, at valve depth. The lift gas in the casing annulus is rapidly transferred into the tubing, beneath the fluid slug that is to be lifted. As this gas enters the tubing, it lifts, or pushes, the slug toward the surface.

It is important to note that a gas lift valve has "spread". This is the difference between the opening and closing pressures of a gas lift valve. It can vary widely, depending on the characteristics of the valve, but can easily be 50 or 60 psi. This means that the casing pressure at which a gas lift valve opens will be higher than the pressure at which the valve closes. In this discussion this is important because the spread of the valve, and the gas pressure and volume in the casing annulus, will determine how much gas enters the tubing while the valve is open. For many wells, the gas volume required to lift a slug to the surface is <u>less</u> than the amount of gas that will pass from the casing to the tubing during the time the gas lift valve is open Normally, injecting gas until the gas lift valve opens will provide enough gas to move the slug to the surface. The best scenario is to stop injecting gas at the moment the gas lift valve opens. There will then be a sufficient volume that passes from the casing to the tubing to lift the slug to the surface. Exceptions to this can be wells that are extremely deep and/or have a smaller that normal annulus. The spread of the valve needs to be considered. Over injecting wastes injection gas, and keeps the tubing pressure higher for a longer period of time, thus inhibiting inflow.

As the fluid travels toward the surface, the gas will have a tendency to break through the slug, and "outrun" much of the fluid. Most of the fluid that is outrun will fall back to the bottom of the well. Wells that are very shallow will experience less fallback problems that deeper ones. A handy "rule of thumb" is that fallback will amount to approximately 5% of the starting slug, per 1000 ft of depth. This means that a 7000 ft well will lost 35% of it's starting slug before it reaches the surface. Not only is this fluid not produced, it raises the average flowing bottom hole pressure, negatively effects the inflow of the well and decreases production.

When an intermittent gas lift well is over injected, and is experiencing fallback problems, the net effect is wasted gas and less production. The next sections will describe what can be done to address these production problems. A description of the system, and criteria for deciding whether a well is an appropriate candidate will also be presented.

ELIMINATING FALLBACK

Fallback is a factor in all intermittent gas-lift wells. The deeper the well, the more significant the fallback problem. Plunger-lift, added to an intermittent gas-lift well, will eliminate fallback. There are mechanical constraints and well production considerations that eliminate plunger-lift as an option on some wells. Plunger-lift is no cure-all, however, when used in conjunction with intermittent gas-lift on the right well, will yield production increases.

A plunger is simply a piston. It's job in an intermittent gas-lift well is to eliminate fallback. By acting as an interface between the liquid slug and the injection gas, fallback is not possible. The mechanical hook-up (see schematic A) is very similar to a standard plunger-lift hook-up on a non gas-lift well. In many cases, the equipment required is exactly the same for both applications.

In an intermittent gas-lift well, a Lubricator and Catcher is mounted above the master valve, and the flow outlet is tied in to the existing flow line. In some cases there is a motor valve installed on the flow line. Usually, there is a motor valve installed on the injection line. This valve is operated by an electronic controller (when a motor valve is used on the flow line, it is also operated by this same controller). Inside the tubing, a Bumper Spring is installed slightly above the injection gas lift valve. The plunger is free to travel between the spring in the tubing, to the spring located inside the surface lubricator.

The key to this operation is for the plunger to already be resting on the bumper spring downhole, when the injection valve opens. As the injection gas enters the tubing through the valve, beneath the plunger, it starts pushing the plunger and the liquid above it, to the surface. This mechanical interface prohibits liquid from falling back to the bottom. All liquid in the tubing above the plunger is lifted to the surface. When the plunger reaches the surface, it moves into the lubricator, and is held there by the gas flow beneath it. Once the gas-lift valve has closed, and the injection gas bled off, the plunger falls back to the bottom, awaiting the next cycle.

CONSIDERATIONS

For plunger-lift to be effective in an intermittent gas-lift well, there are factors which must be considered.

THE PLUNGER MUST BE AT THE BOTTOM

For a plunger to be effective in eliminating fallback, it must be at the bottom of the liquid slug before the next injection cycle begins. All liquid that is above the plunger will be lifted to the surface, while most of the liquid below the plunger will fall back to the bottom. For this reason, a major consideration is that the plunger is able to get to the bottom quickly enough.

One of the biggest limitations to this type operation is not having sufficient time for the plunger to reach the bottom. The deeper the well, the longer the interval between injection cycles must be for the plunger to fall. Plunger fall times can be as less than 100'/min (in fluid) to an excess of 1000'/min in dry tubing. While it is possible to change the injection cycles to give the plunger more fall time, this can have negative effects on production if the cycles were the right cycles for that particular well. This means that some wells could be eliminated as candidates due to short injection cycles.

It is also possible that the plunger will fall slower than normal if there is formation gas entering the tubing. Any gas flow during the fall time, will be attempting to lift the plunger, therefor will retard it's fall speed. If there is sufficient gas, the plunger may stay in the wellhead and not start falling until the gas flow slows. On wells such as these, it is often preferable to install a motor valve on the flow line (see Schematic B). By closing this valve during the plunger fall time, gas flow is stopped, and the plunger can fall faster. This shut in is normally done immediately before the next injection cycle.

The additional motor valve is normally operated by the same controller that opens and closes the injection valve. It is set so that the flow line valve shuts (usually 5 to 10 minutes) between injection cycles. The flow line valve re-opens when the injection valve opens. At the end of the injection cycle, the injection valve closes, It remains closed for the injection off-time, and the flow line valve remains open until just before the next injection cycle.

This type cycle can work quite well, as it allows the well to be open during the majority of the cycle, minimizing back pressure build-up, and shuts in the tubing only long enough to get the plunger to the bottom. By using one controller to operate both valves, synchronization problems (when using two controllers) are eliminated.

TYPE CONTROL: CHOKE vs MOTOR VALVE

Injection gas can be controlled by either a choke, throttling valve, or by means of a motor valve. The choke, or throttling valve allows a measured flow of lift gas to continuously enter the casing. A motor valve allows gas to enter the casing only when it is open; and it is opened and closed intermittently.

The choke (or throttling valve) continues to meter gas into the casing, both during and between gas lift valve opening and closing. When the pressure in the casing annulus builds to the opening pressure of the injection gas lift valve, it opens and allows gas to enter the tubing. The gas that is passing through the gas lift valve is moving at a higher rate than the gas that is being injected through the choke on the surface, therefor, the pressure in the casing drops. It drops until it reaches the closing pressure of the valve. Once the gas lift valve closes, the pressure in the casing starts to build. When it reaches the opening pressure of the valve, gas is injected into the tubing once again. This cycle is repeated continuously.

This is a very simple operation, and requires little surface equipment to regulate the injection flow. It does, however, tend to waste gas. As discussed earlier, the most efficient injection cycle would be to stop injecting the minute the gas lift valve opens. The casing pressure would then drop until the closing pressure of the valve is reached. The pressure in the tubing would then remain the same until gas is re-injected. With choke control this is very difficult. The gas lift valve cannot close until the casing pressure drops to the valve closing pressure. With gas being continually injected, the casing pressure drops more slowly, therefor, more gas is injected, or over injected.

SPECIAL PLUNGERS

HIGH VELOCITY PLUNGERS (see schematic C)

There are plungers that have been designed with the fall rate in mind. At times it is necessary to combine a number of tricks to be able to get the desired results. Take, for example, a deep well that is also producing formation gas, and has relatively short injection cycles. In many cases, with standard equipment this type well would be eliminated as a possible candidate. It is possible to combine using a flowline motor valve (to stop gas flow) with a high fall rate plunger, to get the plunger back to the bottom more quickly.

There are several designs available. Each have their own advantages and limitations. check with your Plunger-Lift supplier for details.

SIDE-POCKET MANDREL PLUNGERS

Side-Pocket mandrels are commonly found in both continuous flow and intermittent gas lift wells. They are an excellent tool, and have numerous advantages. Plunger lifting in a well with side-pocket mandrels can only be done when a special side pocket mandrel plunger (see schematic D) is used.

A side pocket mandrel has a large open area in which a plunger cannot retain it's seal. This special plunger is able to seal because of it's length. By providing a long enough seal, the plunger can maintain it's seal integrity while passing through the mandrel. It's design also provides for alignment orientation when falling through the mandrel.

PARAFFIN CONTROL

The easiest application of all Plunger-Lift applications is for eliminating paraffin. This includes not only intermittent gas-lift wells, but continuous flow gas lift wells, and flowing wells. As a matter of fact, any well that has a plunger traveling inside of the tubing will not have a paraffin build-up. This is provided the plunger is allowed to travel often enough that paraffin in not allowed to form between cycles.

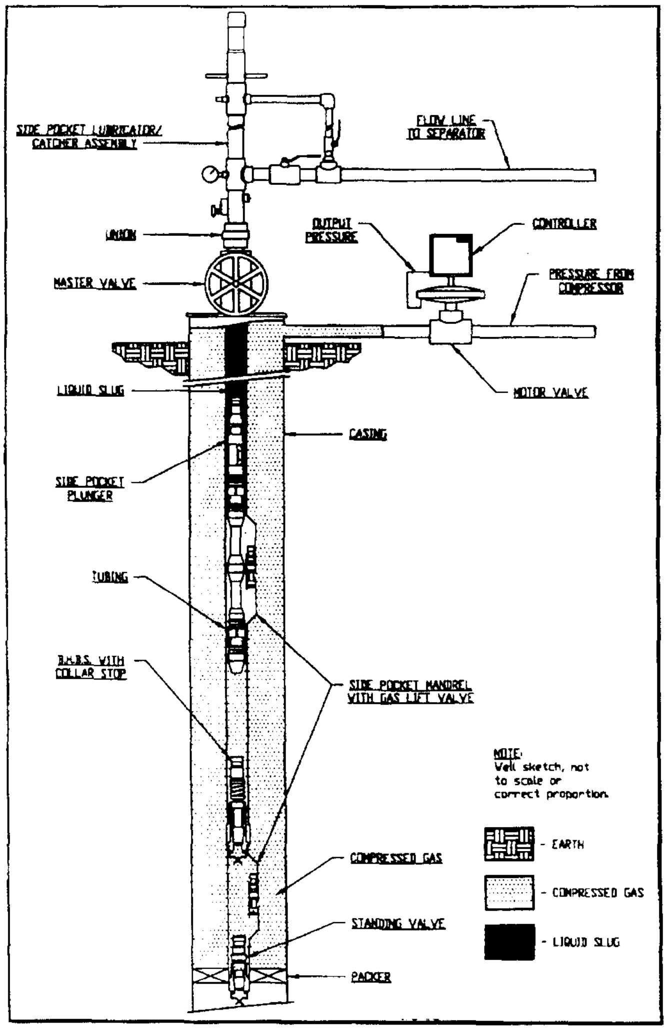
If the goal for installing a plunger is only to control paraffin, the bottom-hole assembly (bumper spring) is not set at the bottom of the well, nor just above the operating valve. It is, instead, set only slightly below the lowest level at which paraffin forms. In this manner, the plunger need not travel the entire length of the tubing, only the distance to the bumper spring. In an intermittent gas-lift well, the cycles need not be altered. The plunger will have enough time to fall during the well's normal cycles. In a flowing or continuous flow gas lift well, there must be a motor valve installed on the flow line to stop the flow so the plunger can fall. In even the most significant paraffin conditions, six to eight cycles per day is adequate to eliminate paraffin accumulation.

As the plunger cycles, the pads, or seals of the plunger keep the tubing walls wiped clean. Paraffin is not allowed to accumulate in any sizeable quantity, and the cycles are repeated often enough that the plunger is able to fall freely. If the plunger isn't cycled often enough paraffin will build up and the plunger can become stuck, or lodged in the paraffin during it's trip to the bottom. The key is not in cutting or removing, it is in not allowing it to form in the first place.

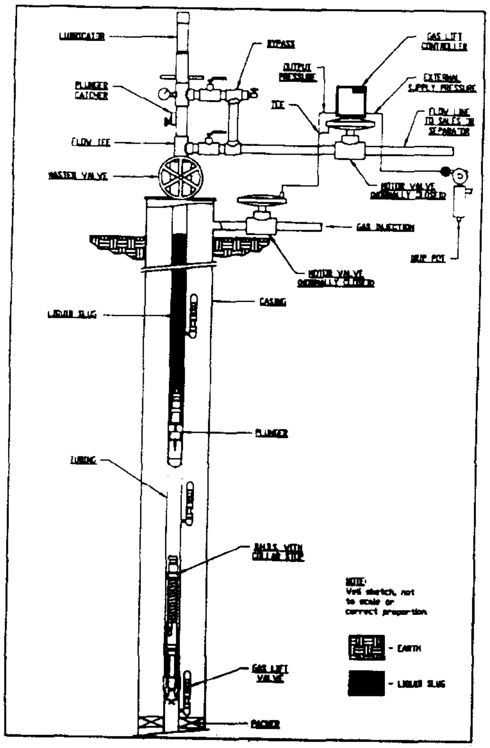
The equipment for paraffin control is often the same equipment used in other applications. The only exception being where there is a rapid build-up, and a special plunger is required to fall through a small accumulation. In this application, a collapsible plunger is used that has a smaller outside diameter when falling so that it will not get hung up in paraffin. When it reaches the bottom it expands to it's original size and is able to wipe the paraffin out during it's ascent.

CONCLUSION

Combining Plunger-Lift with intermittent gas-lift is a natural. It is, however, used infrequently in the United States. Problems with cycling due to free gas, short cycles, deep wells, and diameter restrictions have discouraged many operators from combining these production tools. With today's new generation of controllers, special clearance plungers, fast falling plungers, collapsible plungers, and with more field experience, most of the old problems have been eliminated. It gives the prudent operator another option to help increase productivity, and profits.



Schematic A



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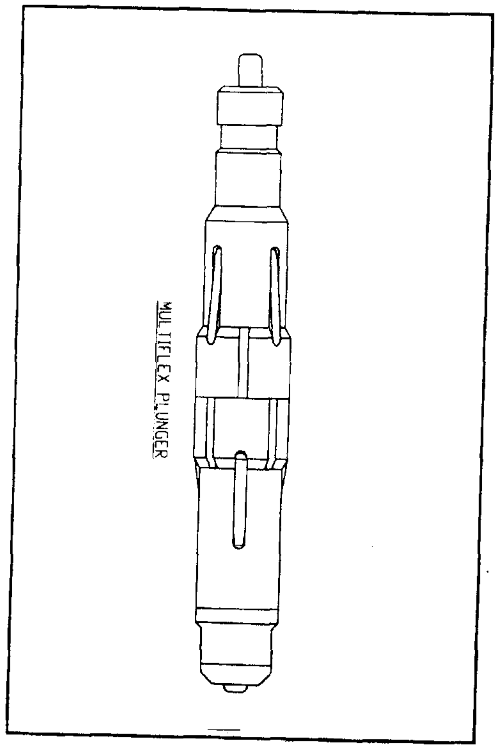
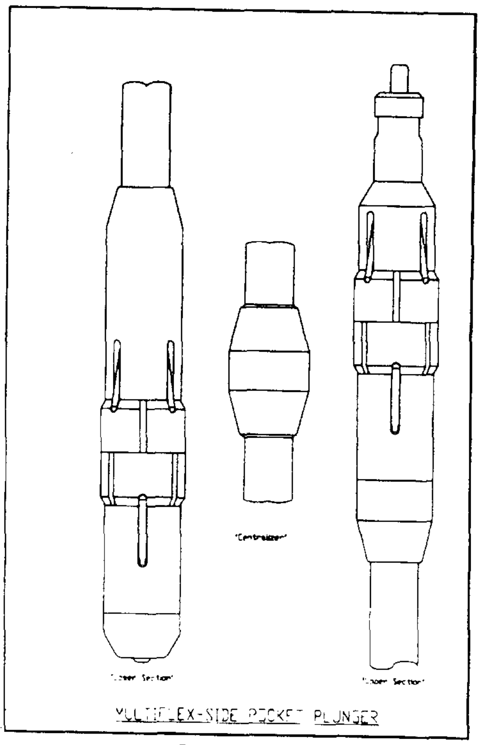
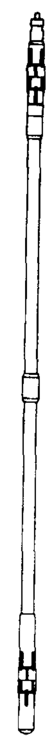


Schematic C



Schematic D



Schematic D