Plunger Lift Operations

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Introduction

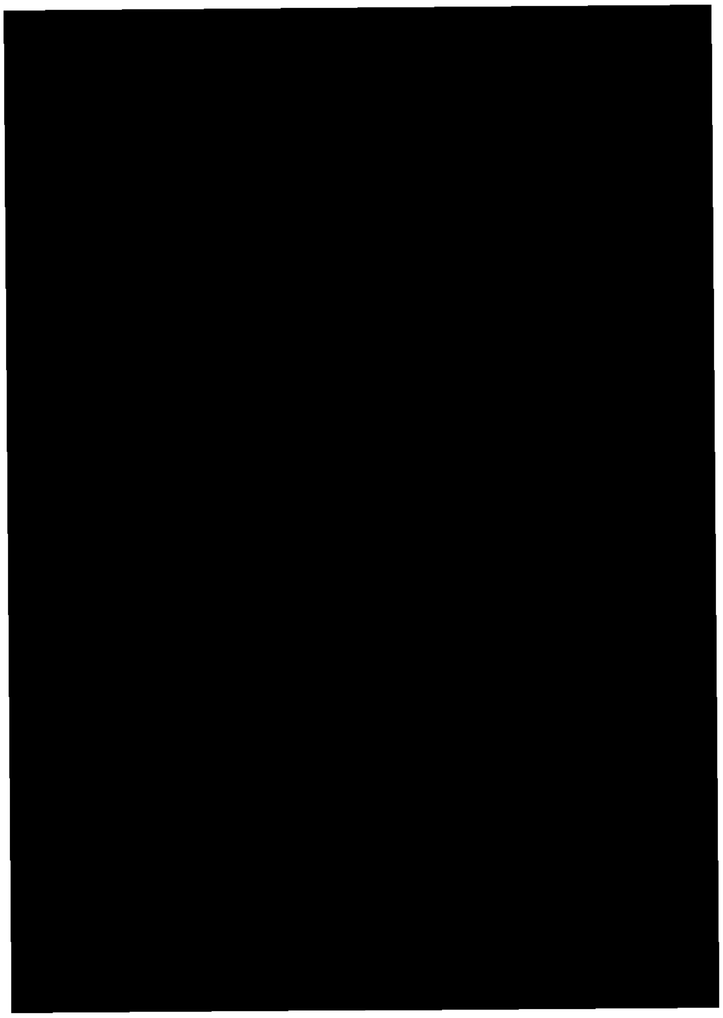
We could easily think of Plunger Lift as the ultimate in long stroke pumping. This is true because we have an expanding piston operating the full length of standard A. P. I. tubing without direct connection with surface mechanical energy.

Rather than using the term "Pumping," we might think of Plunger Lift as a refinement of gas lift. Plunger Lift operations are a form of intermitting gas lift, gas lift here referring to both natural flow and where additional gas is being injected, with the plunger constituting a seal between well liquids and propulsion gas. In performing this seal, the plunger minimizes the slippage, the fallback of liquids through the ascending gases, which is encountered when gas lifting low volume wells. The plunger is especially effective in deep wells with small production. It is in such wells that conservation of energy through the use of the plunger is most apparent. This, in most instances, permits a higher degree of effectiveness and efficiency than has ever before been possible.

How Plunger Lift Operates Including Description of Equipment and Its Functions

The well tubing, from the producing zone to the surface, is used as a working barrel. The expanding plunger is propelled from the bottom of the tubing to the surface by gas under pressure. It sets closelv in the tubing and maintains a seal between the lifting gas and the lifted fluid while passing through the tubing and collars.

The expanding plunger is rugged in design, and precision made of stainless steel alloys. The two sets of expanding elements comprise complimentary depression bars and ring segments that are held in their expanded, interlocked position by means of a compression type spring placed under each ring segment. The valve cage, constructed of a non-magnetic alloy, houses the plunger valve. In the mid-section a split ring is provided for the easy removal of the upper and lower sets of ring segments and depression bars.



A desirable feature of the expanding plunger assembly is the valve which is the only operating element, being moved to open position at the upper end of the plunger travel so that the plunger may fall by gravity. The valve is closed upon contact with the footpiece at the lower end of its stroke. The valve is held in the open position by a permanent magnet during its down well stroke and is held in the closed position by a frictional detent during the plunger up-stroke.

The plunger is used in standard A. P. I. plain or upset well tubing. Nominal plunger sizes are 2", 2-1/2", 3" and 4". Larger sizes are available for running in casing when no tubing is used.

Before the plunger is first put into operation, it is necessary to remove interior roughness and scale deposits from the well tubing, in order to provide "Free Stroking" for the plunger. This is done with two or three "V" type cutter broaches which are furnished in varying diameters up to within 0.030" larger than the plunger diameter.

Broaches are run individually on a wire line with jars and sinker bar. Field experience has taught us that a thorough broaching job is one of the most essential factors for trouble free operation.

Also, prior to placing the plunger in operation, it is necessary to install the down well removable footpiece, the bumper housing assembly, the diaphragm motor valve, and the cycle controller.

The footpiece assembly consists of: (1) A combination Otis Type fishing neck and footpiece seat which the plunger strikes to close its valve; (2) A compression type spring which absorbs the plunger impact in the final stage of its descent; (3) a bottom adapter to which may be attached:

(a) Any A. P. I. hold down for locking into a corresponding type pump shoe,

(b) An Otis "latch on" hold down which locks over the fishing neck of a Type FF Pack-Off Anchor Stop or Otis Collar Stop,

(c) Special devices to lock in any tubing string.

If the tubing string has previously been fitted with a pump shoe and tubing is not being pulled, the footpiece may be dropped free from the surface. If tubing has been pulled and the pump shoe is installed, the footpiece can be put in place at the surface prior to running pipe.

By means of a wire line, the anchor stop can be set anywhere in the tubing string to accommodate various depths of lift, and is readily changed to meet varying production requirements. This is also true of the collar stop which may be set in any tubing collar. In both cases, the footpiece is generally dropped free from the surface. It can be fished from its locked postion by means of a wire line or sand line.

The Bumper Housing Assembly is surface mounted on the wellhead master valve by means of a stack nipple customarily furnished with 8 round EUE tubing thread for mechanical strength. The housings are made in four sizes, 2", 2-1/2", 3" and 4."

The bumper housing assembly serves to stop plunger travel in the final stage of its ascent. The compression spring and mechanical valve opener are housed in the upper section of the assembly. The plunger impact is absorbed by the compression spring. Simultaneously, the mechanical opener opens the plunger valve.

The closing cap is held in place with an A. P. I. tool joint thread, sealed by an "O" ring. On requirement it is furnished with an inner tubing thread and plug for the mounting of a swab or piano wire lubricator. Below the closing cap two diameterically opposite 2" outlet connections are provided for flow line connections.

The main diaphragm motor valve is installed in the well flow line system. Its function is to open and close the well, in response to a pneumatic impulse from the pressure cycle controller.

It is furnished in 1" and 2" sizes, screwed ends, cast steel body suitable for 1500 psi working pressure. The inner valve is single port, stainless steel trim stellite faced. Valve action is normally closed, opens with a pressure of 20 psi imposed on the diaphragm member.

The pilot unloading valve is mounted on the motor valve, and is pneumatically interconnected with it. Its function is to measure down stream pressure and modulate the main valve. It automatically controls a selected down stream pressure, to safeguard low pressure flow line and oil-gas separator systems.

The Taylor Type C-1 cycle controller is an instrument whose function is to measure and control the well surface pressure.

With the plunger stroking the well from one extreme to the other, a pressure cycle is established. The magnitude and frequency of the cycle is generally determined by the quantity of lifted fluid, well depth, and gas volume within the well.

The cycle is controlled by the instrument, arranged to pneumatically operate the main diaphragm valve. The measured high point of the cycle signifies that the plunger is on the bottom. The motor valve is opened by the instrument commencing the load stroke. Upon stroke completion the instrument again acts through a pneumatic over ride of the bumper housing trigger-cam, to close the motor valve. Low point of the cycle is determined by the amount of pressure decrease required to surface the plunger.

The cycle becomes continuous and the automatic control of it stabilizes the operation of the well. Pressure settings can be varied to achieve the most suitable operating conditions.

The Ideal Taylor Type C-1 is furnished recording, with 12" chart, spring wound clock driven. Alloy steel pressure measuring element is furnished for any operating range. Complete mechanism assembled in rectangular, weatherproof case, yoke mounted. Controller is operated with a 20 psi supply medium, provided for by the accessory group including pressure regulator, strainer, relief valve, charts and ink.

The Fisher Cycle Controller performs the same function as the Ideal Taylor. It is furnished non-recording, with its control mechanism assembled in a square weather-proof case. It is mounted integrally with accessories on the main diaphragm motor structure. An alloy steel pressure measuring element is furnished for any operating range. A separate single or two pen pressure recorder is required when this instument is used.

Now that we have reviewed the component parts individually, we can follow the plunger through a complete cycle and see how the individual parts function together.

How it works is shown by this sequence of five illustrations. A typical open system well has been selected. A pressure cycle has been started with the plunger descending at which point the casing pressure is low. When the high point has been reached the well is then automatically opened, causing the plunger to then begin its stroke to the surface.

As the plunger ascends from its surrounding liquid, gas expands at an increasing rate to propel plunger and load to the surface.

Illustration 1 shows the well closed—plunger with its valve open descending to well bottom. Casing pressure at low point of cycle phase.

Illustration 2 shows the well closed—plunger on bottom, having struck footpiece closing its valve. Casing pressure increasing from low point.

Illustration 3 shows the well open at casing pressure high point. Plunger starts to ascend with load, as tubing pressure drops rapidly.

Illustration 4 shows the well open—casing pressure decreasing—tubing pressure decreases to surface flow line pressure. Gas expands, propelling plunger with its load to surface.

Illustration 5 shows the well closed—plunger has completed load stroke, having displaced gas and liquid to flow line system. Its valve is automatically opened and simultaneously well is closed, permitting plunger to descend. Casing pressure is at previous low completing the cycle.

What Plunger Lift Will Do

Mimimize Slippage

The plunger will act as a seal between well liquids and propulsion gas and thereby minimize slippage. In minimizing the fall back of well liquids through ascending gas, the plunger will permit the producing of heavy crude wells and low gas-liquid ratio wells which will not flow continuously. The fall back of the well liquid, under natural flowing conditions, will for a period of time, cause continual build up in the bottom of the tubing and annular space, causing back pressure to be built up against the producing formation.

In many cases this will not be a column of liquid having the same gradient as the average gradient of the well liquid alone. It will be a heavy aeriated column with a high flowing gradient. For example, the static fluid gradient may be 0.40. The flowing gradient might be 0.08, and the flowing gradient with slippage present may be 0.20 in the lower part of the tubing string. If the heavier flowing gradient is present in the lower 1500 feet of the tubing, it would exert a pressure of 1500 x 0.20 or 300 psi. Under good flowing conditions this pressure would be 1500 x 0.08 or 120 psi. The back pressure will increase to a point where the formation pressure can no longer overcome it, and the well will load up and die. During this period of liquid fall back the ascending gas will be produced from the tubing, and will deliver a total gas-liquid ratio which is higher than the actual formation gas-liquid ratio This gas is lost energy which could be used to take the well to depletion under Plunger Lift operation. A large percent of slippage will occur in gas lift not employing the plunger when lifting a high fluid gradient well, and will necessitate operating with high gas-liquid ratios. Maximum production cannot be realized under these conditions.

Increased Efficiency and Effectiveness

The plunger will increase efficiency through less slippage and increase effectiveness through lower operating pressures. Generally speaking, the word efficiency is used to mean the ratio of the theoretical minimum volume of gas required to lift a quantity of liquid, to the actual volume of gas required to lift this same quantity. A more technical definition would be—the ratio of the theoretical minimum work, in foot-pounds, required to lift a quantity of liquid, to the energy in foot-pounds, actually expended in lifting the same quantity.

The term effectiveness is usually taken to mean the quantity (oil) being produced as compared to the quantity of liquid which the well is capable of producing. In some cases efficiency is of the utmost importance, especially where extraneous gas must be used, or where extraction plants are overloaded. It is important that the highest degree of effectiveness be gained under efficient operation. In some cases effectiveness is paramount, with no consideration being given to efficiency. Where there are no gas gathering facilities and state restrictions are lenient, the operator may desire to lower operating pressures, and produce as much oil as possible with little attention being given to the gas required.

The plunger makes possible higher efficiencies thru minimizing slippage especially in small producers. Without the seal to prevent slippage, a higher produced gas-liquid ratio exists, and, a larger volume of gas is required (or more energy expended) in lifting the liquid. The efficiency is also increased on wells which tend to flow when kept unloaded by the plunger thru the shutting in of the tubing after each plunger cycle, the effect is, gas conservation.

The increased effectiveness can be partially attributed to the minimizing of slippage. The quantity of liquid which would normally fall back is reduced and, therefore, there is not as great a back pressure on the formation. This permits lower operating pressures. The flexibility in different methods of operation and installation of Plunger Lift permits lower operating pressures and increased effectiveness.

Reduction of Total Gas—Liquid Ratios

We previously discussed the better control of gas due to slippage under efficiencies. This plus operating pressure control and intermitting flow control are the advantages for ratio control.

In a free gas reservoir there are limits beyond which we can successfully operate. This is easily understood when you consider that on the extremely high ratio wells the casing pressure drop would be quite low on the lift cycle of the plunger. Then the very rapid pressure build up would open the flow line before the plunger has had time to get to the bottom. For example, the ratio limit on a 7,000 foot well would be approximately 10,000 cf per bbl.

Increased Production

Increased production has been gained through the reduction of slippage. This reduction prevents the build up of back pressure on the producing formation, permitting a lower operating pressure. The lower the operating pressure, the more production the formation should yield.

Operates On Low Gas Pressure

In flowing wells without plungers a higher pressure is required to overcome the liquids which are falling back. If higher pressures are not maintained, these wells will load up and die in a shorter period of time. It is necessary to have the higher pressure in these wells so that the starting velocities from the formation will be greater. With the higher velocities, less slippage is encountered; but the higher velocity means great friction loss. The Plunger Lift overcomes this problem.

Lower Gas Injection Pressure Where Extraneous Gas Is Required

In other methods of intermitting gas lift, higher gas injection pressures are required to assure higher velocities to reduce slippage. Plunger operation does not require the high initial velocity, therefore, lower injection pressures can be used.

Optional Working Pressures

While producing with Plunger Lift it is possible to adjust the working pressure to the method of production desired, and also to fit changing well conditions. If effectiveness is desired, the operator may lower working pressure to a minimum for depth and production of the well. The lower pressure may not be the point of greatest efficiency. If greater efficiency is desired, pressure may be increased in most instances without too much loss in production, and fewer cycles will be necessary. Also, the higher pressures gives the operator a greater safety factor for operation, and in low PI wells, will not reduce production a great amount. During months and/or years of operation, changing well conditions can be met. As production declines, it is a very simple procedure to lower the working pressure by means of the controller.

Eliminates Pulling Jobs

Since the expanding plunger does operate in standard API tubing and the tubing may be broached in place, it is not required to pull tubing during the initial installation (unless defective tubing is present). Periodic trapping and examination of plunger permits repair without fishing or pulling tubing.

Other Features

a. Low initial cost.

b. Low operating cost (For example, there have been two plunger installations operating in the Keystone Field for the past 29 months with no expense other than a controller door which was permitted to swing open in a high wind. Wear on the expanding segments has been measured and at the present rate of wear, the expanding blades can be used for approximately 25 years).

c. Tubing kept clean of paraffin and other foreign material.

d. No depth limit.

e. Operation not affected by crooked hole.

f. No live load on tubing.

g. No tubing packer necessary.

h. Not subject to gas lock.

i. Quick plunger repair and replacement.

j. Conventional tubing hanger.

k. Conventional API bottom lock on footpiece or Otis latch on.

l. Magnetic plunger with valve lock assures full stroking.

m. Mechanical plunger valve opener.

n. Simple, positive surface control.

Types of Wells Suitable For Plunger Lift

As a form of artificial lift, the plunger is rather widespread in its application. It is more universally applied to "open system" wells. It can be applied to "closed system" wells.

Many wells lend themselves appropriately to plunger lift when other methods have proven uneconomical.

These include wells which are small producers having high injection or formation gas-liquid ratios. They usually have low productivity indices and can be produced to economic depletion by plunger lift.

Wells having injection gas available from a compressor plant, or from other wells, where production is within the plunger's capacity qualify themselves.

The plunger is ideally suited to weak flowing wells, which normally load up and die. Wells produced by stop cocking means are benefited in that lower operating pressures, gas conservation and increased production are usually realized with plunger lift.

Gaseous well produced by rod pumps or other types of reciprocating pumps, being subject to "gas lock" are suitable for plunger lift. They must have medium to high bottom hole pressures, relatively low rates of production, and sufficient formation gas for operation.

To qualify the use of Plunger Lift a number of the well's physical characteristics should be carefully reviewed. These characteristics are:

1. Bottom Hole Pressure—The existing field pressure, rate of decline and productivity index (P. I.) should be considered. In general, 400 psi is considered a minimum for original installations.

2. Productivity Index—Bottom hole pressure, well depth, size of tubing and volume of gas available set the limits of this requirement. Generally, a PI of 0.2 to 0.3 or less is recommended although certain field conditions may justify the producing of higher P. I. wells by Plunger Lift.

3. Gas Volume and Bottom Hole Lifting Pressure—These components vary with individual well conditions and the well's production history should be reviewed to determine the volume and pressure requirements.

In general the minimum gas volume requirements is 250-350 cu. ft./bbl. per 1000' of lift, neglecting flow line and separator system pressure.

Well depth, tubing size, separator pressure, character and quantity of well liquids effect these requirements. Consequently the consideration of (G. O. R.) is important.

4. Oil Gravity—26 A. P. I. gravity, or lighter, heavier oils have a diminishing quantity of gas in solution.

5. Wet Wells—will produce any percentage water content well.

6. Paraffin—The plunger will keep paraffin removed from the tubing wall. It further tends to prevent deposition in the flow line system.

7. On wells where there is sufficient gas volume, pressure and liquid, the nominal lifting capacity of a plunger lift system is tabulated below:

Plunger Size	**5000'** BPD	**8000'** BPD	**10000'** BPD
2"	110	75	50
2-1/2"	225	150	125
3"	450	300	250
4"	900	600	500

Results of Actual Installations

We can now consider examples of actual installations for the various types of wells suitable for Plunger Lift.

Example of Weak Flowing Well

Well Data: Depth 7700 Feet. Tubing 2-1/2" to 7635 Feet. Static BHP 1400 psi. Productivity index 0.09. Trap pressure 85 psi. Length flow line 100 feet.

Production History Prior to Plunger: Flowing by heads required frequent swabbing. In May 1952, flowed 38 bbls. 30 degree oil, 2 bbls. water, 1" choke, with a GLR of 4200 cf/bbl and a casing pressure of 600 psi.

Production History Following Plunger Installation: Plunger installed 5-29-52. In July 1952, produced 66 bbls oil, 6 bbls water, on a 1" choke with a GLR of 2780 cf-bbl, and a casing pressure of 300 psi to 260 psi. Plunger making 54 cycles per day.

Example of Well With Too Much Formation Gas For Pumping

Well Data: Depth 8569 Feet. Tubing 2-1/2" to 8477 feet. Static BHP 1200 psi. Productivity index 0.03. Trap pressure 30 psi.

Production History Prior To Plunger: Flowing, November 1951, produced 8 bbls of 33 degree oil, 1 bbl water, 14/64" choke, GLR 13,900 cf/bbls, casing pressure 700 psi, tubing pressure 125 psi. Pumping unit was installed soon after this test but proved unsatisfactory due to excessive formation gas.

Production History Following Plunger Installation: Plunger installed, 2-20-52. On 3-6-52, the well produced 21 bbls oil, 1 bbl water on 27/64 inch choke, with a GLR of 3,635 cf/bbl and a casing pressure of 295 psi to 260 psi. Plunger making 16 cycles per day.

Example of GOR Control

Well Data: Depth 6600 feet. Tubing 2" to approx. 6600 feet. Static BHP 1000 psi. Trap pressure 40 psi.

Production History Prior to Plunger: Flowing 10-1-52, produced 12 bbls 38 degree oil, no water, 17/64" choke, GOR 8000 cf/bbl, casing pressure 500 psi.

Production History Following Plunger Installation: Plunger installed, 10-13-52. On 10-27-52, the well produced 27 bbls oil, no water 1/2" choke, GOR 2500 cf/bbl, casing pressure 400 psi.

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