Plunger Lift

As they mature, gas wells exhibit a decrease in bottomhole pressures and the production velocities necessary to carry liquids—produced water, oil and condensate—to the surface. Over time, this liquid accumulates in the production tubing downhole, creating a condition known as *liquid loading*.

The well loses energy as the hydrostatic head created by the accumulated liquids counters the reservoir's natural pressure. Gas flow becomes intermittent, lowering the production rate, and eventually stops if liquid loading is not addressed.

Several methods are used to remove accumulated liquids and restore regular gas flow, including the use of *foamers* (e.g., soap sticks)—surfactants that once injected or dropped into the well, mix with the liquids downhole to create a low-density foam, which can be lifted more easily to surface. This method is simple in principle but introduces chemical costs, often requires a downhole injection system and is less effective if significant quantities of liquid hydrocarbon are present.

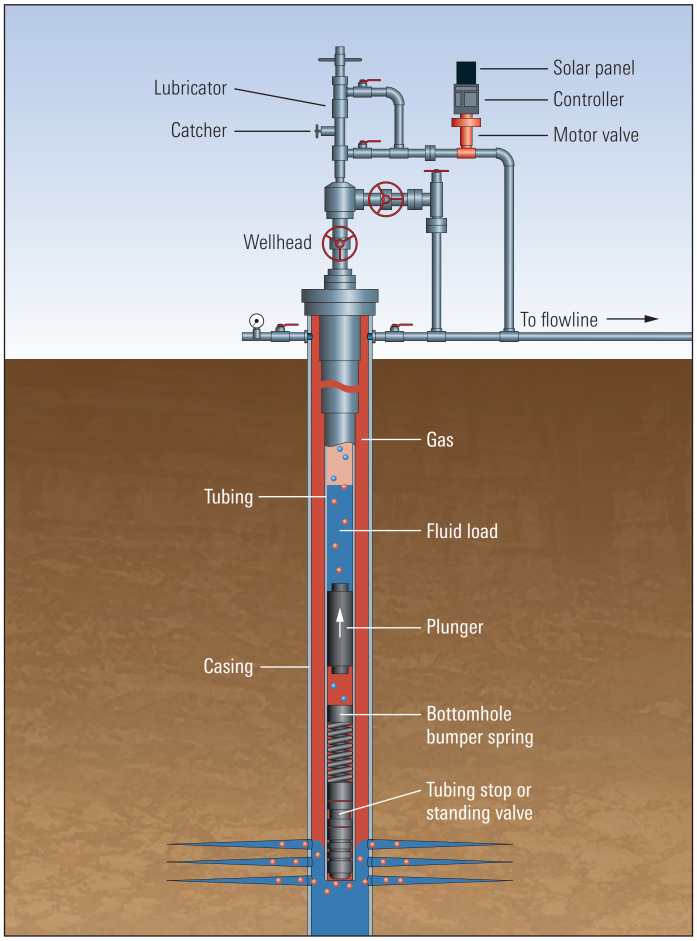

Figure 1. The main components of a plunger lift system on an onshore gas well. Subsurface components include a plunger (including a bypass valve), a bottomhole bumper spring, and a standing valve, which prevents fluids from flowing out of the bottom of the tubing. Surface components are attached to the wellhead and include a motor valve that has a solar-powered controller. A lubricator and catcher assembly accepts the plunger as it rises through the wellhead, opening up a flow path for the produced gas to the flowline. A wellhead arrival sensor detects the arrival of the plunger at the surface.

Venting the well to atmospheric pressure, a process known as a *well blowdown,* will usually remove fluids from the wellbore and reestablish gas flow. However, this process results in gas losses and increased emissions of methane, a greenhouse gas, to the atmosphere. Moreover, it must be repeated as liquids reaccumulate in the well.

Artificial Lift for Addressing Liquid Loading

Plunger lift is an artificial lift method that offers an economical and established technique for removing liquids from aging gas wells while minimizing gas losses and methane emissions. As with other forms of artificial lift, plunger lift systems remove liquids from the wellbore so that the well can be produced at low bottomhole pressures. Production engineers consider plunger lift to be one of the simplest forms of artificial lift because it uses the well's own energy to remove accumulated liquids and sustain gas production.

The use of plunger lift systems dates back to the 1950s and 1960s, when their primary application was to assist gas lift systems in oil wells. They slowly gained acceptance as a lift method for liquid-loaded gas wells, and since the 1980s, this has been their primary application.

Architecture of a Plunger Lift System

Whether the system is used in a gas well or an oil well, the mechanics of a plunger lift system are the same. A *plunger* or piston incorporating a bypass valve travels through the production tubing to the bottom of the well where it lands on a bottomhole bumper spring (Figure 1). The plunger has enough clearance to allow it to move unhindered up and down the tubing string. However, the clearance is small enough to create a mechanical seal between the fluids above and below the plunger when the bypass valve is closed. The up and down movement of the plunger not only controls gas production from the well but also scrapes any initial appearances of paraffin and scale deposits from the wellbore walls and lifts them to the surface.

During the plunger downstroke, the tubing string tends to elongate and on the upstroke, it compresses. A *tubing anchor* is affixed to the end of the tubing to minimize this tubing movement. By holding the tubing rigidly in place, the tubing anchor also minimizes helical buckling and plunger-on-tubing wear that occurs during load transfer.

At the surface, a motor valve assembly controlled by a microprocessor controller automatically regulates production. The controller is typically powered by a solar battery and can use simple timer cycles, or it can consist of a solid-state memory and programmable functions based on process sensors. A short section of pipe known as a *lubricator* extends above the wellhead and serves to catch the plunger after it reaches the surface.

Operating Cycle

Typically, plunger lift operation is a cyclical process of shut-in (or no-flow) and flow periods (Figure 2). The cycle begins in the shut-in mode with the plunger resting on the bottomhole bumper spring at the base of the well. The surface valve is in the closed position, which allows well pressure to build as gas accumulates in the annular space between the casing and the tubing.

When the pressure reaches a preset level, the controller opens the surface valve. Tubing pressure quickly drops to line pressure, allowing pressurized gas from the annulus to enter the tubing below the plunger. The gas pushes the plunger and the fluid column above it to the surface.

The fluids above the plunger flow through an upper and lower outlet on the wellhead and into the flowline. The plunger stops in a spring-loaded receiver in the lubricator. When the plunger is no longer in the flow path, the gas that supplied the lifting energy flows through the lower outlet into the flowline.

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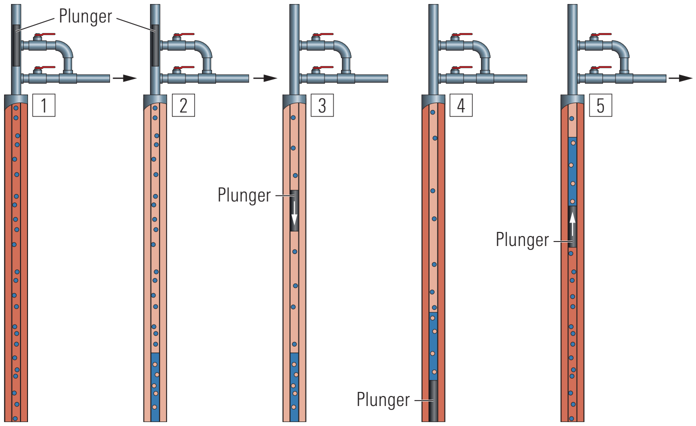

Figure 2. A conventional plunger lift cycle. (1) Gas production is at a maximum rate without liquid loading. (2) Rate and flowing pressure decline naturally (light red) as liquid (blue) accumulates in the tubing. (3) After flowing pressure or flow rate drops to a set level, the surface valve closes, and the plunger drops through the gas and liquid. A bypass valve in the plunger enables efficient descent and closes when the plunger lands on the bottomhole bumper spring. (4) The closed surface valve allows reservoir gas to accumulate and build up pressure (red) in the casing-tubing annulus. (5) The surface valve is then opened, allowing the pressurized annulus gas to push the plunger up the tubing, unloading the liquid via the flowline. The plunger is caught in the lubricator. Gas production restarts at maximum rate and the cycle begins again.

The gas flow rate and pressure at the wellhead will begin to drop as produced gas flows out of the well, causing wellbore liquids to start falling back down and accumulating in the wellbore. Once the pressure drops below a preset level, the automatic controller closes the surface valve and releases the plunger, which falls back down to the bottomhole bumper spring. The cycle begins anew as liquid loads above the plunger and annular gas pressure builds. Controlling the plunger travel speed and cycle times is critical to safety and efficiency.

Benefits and Limitations

Plunger lift systems provide several economic and environmental benefits compared with other solutions for liquid-loaded gas wells. Because they use the built-up pressure of the well's own gas to effect liquid removal, they typically do not require outside energy sources.

The costs of installing and maintaining a plunger lift system are generally lower than the corresponding costs for beam pumping equipment. Overall maintenance costs are reduced because periodic remedial treatments such as well blowdowns or *swabbing*—in which toolstrings that have rubber-cupped seals are run up the tubing to carry liquids from the well—may no longer be necessary. And unlike these other remedial measures, plunger lift provides regular fluid removal, which enables the well to continuously produce gas without halting production. In addition, wells that continuously move water out of the well have demonstrated an increased potential for producing greater volumes of condensate and oil.

Because of the regular scraping action of the plunger against the tubing walls, plunger lift systems prevent the buildup of deposits in wells prone to paraffin or scale accumulation. This reduces or eliminates the need for chemical or swabbing treatments. Moreover, lower methane emissions have been reported when plunger lift systems are used because these systems reduce or eliminate well interventions.

Plunger lift systems are most effective in wells that have low bottomhole pressures, high gas/liquid ratios (GLRs) and liquid production of less than approximately 21 m^3/d [130 bbl/d]. While makeup gas or compression can be used to address inadequate GLR and buildup pressure requirements, these systems are most effective in wells where formation gas is the only gas source. Candidate wells should produce at least 11.3 m^3 [400 ft^3] of gas per barrel of liquid per 300 m [1,000 ft] of depth. Wells with a shut-in wellhead pressure that is 1.5 times the surface flowline pressure are also good candidates.

Seal efficiency is critical for effective plunger lift operations These systems require a uniform inside diameter along the tubing string to allow the plunger to travel freely from the bottom of the well to the surface while carrying well liquids and producing gas. For wells that produce sand—either from loose, unconsolidated formations or from sand or proppant used in hydraulic fracturing operations—operators run the risk of the plunger sustaining erosive damage or getting stuck on its way up or down the tubing.

Common Applications

While they are commonly associated with increasing gas production in high-GLR wells, plunger lift systems have also been used successfully to boost oil production in high-GLR oil wells. In addition, they have been used in conjunction with intermittent *gas lift operations* that produce reservoir fluid sporadically by displacing liquid slugs with high-pressure injection gas.

The most desirable wellbore configuration for plunger lift is in wells that have an open annulus. In this configuration, gas in the annular space can work freely on the plunger and liquid slug to provide lift with little restriction. Plunger lift systems have also been successfully deployed in other well configurations, including wells with packers, slimhole wells containing 2⅞-in. and 3½-in. casing and deviated wells. In addition, plunger lift systems can work through coiled tubing installed in the well as a velocity string.

New Developments

In recent years, plunger lift operations have incorporated automatic electronic controllers. Battery-powered electronic controls that have solid-state circuitry regulate the cycling of the motor valve in response to plunger arrival at the wellhead, line pressures, liquid levels or pressure differentials. These controllers also help streamline the installation process and save the man-hours required to manually fine-tune the plunger system.

New information technology systems, such as smart automation, online data management and satellite communications, have streamlined plunger lift monitoring and control by enabling operators to manage plunger lift systems remotely, without the need for routine in-person field visits.

Wireless monitoring and control systems that transmit analog or digital signals via radio or from a central processing device are gaining greater acceptance, particularly among operators using plunger lift in many hundreds or thousands of wells. Wireless systems can be set up on location in less than an hour, as opposed to the several days required for conventional wired systems, and without the need for conduits or trenches for buried cables. The wirelessly transmitted data, which include liquid level, flow, pressure, temperature, plunger location and system alarms, can be monitored remotely and in real time. Operators use this information to optimize their field crew deployments by sending crews to only those wells that require maintenance or repairs, increasing efficiency and reducing costs.

Even with these electronic advances, experienced well personnel are critical to effective plunger lift operations. Operators must understand the mechanism for well loading, have a basic understanding of inflow performance and be able to troubleshoot wells based on tubing and casing pressures and flow performance.