The Lease Pumper's Handbook

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Chapter 6
Mechanical Lift

Section A

PUMP OPERATION

There are four types of power that are commonly used to provide artificial lift in the oil field. There are:

- Mechanical lift powered by a motor or engine on the surface
- Hydraulic lift, where oil or water is pumped down into the well to operate a hydraulic pump
- Electric submersible pump, where a pump at the bottom of the well is driven by electricity from the surface
- Gas lift, where natural gas injected into the tubing at intervals lightens the weight of the fluid, helping it rise to the surface

All four of these systems offer advantages and disadvantages for specific situations. During the life of a well, more than one of these systems may be used. Occasionally the same type of system may be installed a second time on the same well. Mechanical lift is one of the more commonly used forms of artificial lift and is the subject of this section. The other types of lift are discussed in the next three chapters.

A-1. Application of Mechanical Pumping.

The mechanical pumping unit remains as one of the best ways to produce artificial lift wells. It is also satisfactory for marginally producing wells, and the majority of all artificial lift wells use mechanical lift.

This system of pumping works well for low production because the surface equipment requires very little daily attention. Each installation is an independent system, is economical to maintain, is easily automated, and is ideal for both intermittent as well as continuous production.

Other lift methods may be more appropriate for a specific situation and for higher production rates, but for many applications mechanical lift is ideal, including in shallow offshore wells.

A-2. How Mechanical Lift Works.

The mechanical pumping unit works on the same operating principles as a windmill or any water well that has a string of sucker rods, a standing and a traveling ball on the bottom, and power at the top. Figure 1 shows a typical pumping unit. These systems, sometimes called *rod pumping* units, work with an up and down reciprocating motion.

Figure 1. A conventional beam-style pumping unit.

The crank of the pumping unit is driven in a circular motion by the rotation of the *sheaves* or pulleys, belts, and gearbox. The gearbox is driven by the *prime mover,* generally a gas-powered engine or an electric motor. The pitman arms are connected to the walking beam, and the rotary action is converted into reciprocating power to the walking beam and the horse head. A set of counterweights offsets the weight of the string of rods and part of the weight of the fluid in the tubing. The string of rods usually extends through the tubing to the bottom of the well, and a pump is installed below the fluid level at the bottom of the hole. By using a ball-and-seat style of standing and traveling valves, the liquid—usually a combination of oil and water—is pumped from the bottom of the oil well to the surface, through the flow line, and into the tank battery.

As the pumping unit starts, the head of the pumping unit moves upward, lifting the sucker rod string and the plunger in the pump. The traveling ball or valve closes so that oil cannot pass through the plunger as it moves upward. This action lifts the fluid in the tubing string toward the surface, while also creating reduced pressure below the plunger. The standing valve in the bottom of the pump opens due to the reduced pressure, allowing additional fluid to enter the bottom of the pump.

As the rod string starts moving downward, the increased pressure from above closes the standing valve in the bottom of the pump. This prevents the oil that has entered the pump barrel from flowing back into the formation and allows pressure to build up between the valves, which opens the traveling valve as the pressure between the valves grows greater than the weight of the fluid in the tubing. The plunger passes down through the fluid that entered the pump barrel during the upstroke, trapping it on top of the plunger once the traveling valve closes as the next upstroke begins, and the cycle will be repeated. The time required for each cycle is determined by how the pumping unit is configured, including the speed of the prime mover, the ratio of gears in the gearbox, and the sizes of the sheaves or pulleys. This cycle time is referred to as *strokes per minute* (SPM) and is partially determined by the *revolutions per minute* (RPM) of the prime mover.

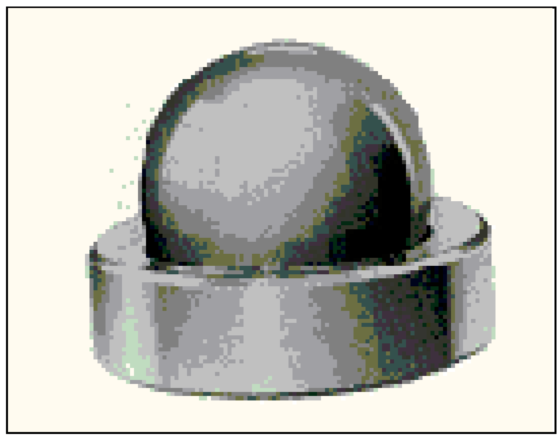

Figure 2. A ball and seat valve, a design commonly used for the standing and traveling valves in mechanical lift systems.

This description of mechanical pumping action shows that the unit lifts liquids to the surface only on the upstroke. On the other hand, the plunger in a hydraulic lift pump lifts liquid on the upstroke and also on the downstroke. Since no rods are moving, this pump can also move much more rapidly than the rod pump, so it is capable of lifting a much higher volume of liquid.

The electric submersible pump and gas lift systems also lift continuously while in operation. Thus, these three systems are capable of lifting a higher volume per day than mechanical lift systems. However, since most wells do not run continuously, whether lift occurs during the whole operation or only half of the cycle is not necessarily the most important consideration in the choice of an artificial lift system.

As the rod string moves up and down during the pumping cycle, many changes occur downhole.

- *As the rod string moves upward,* the weight of the column of oil in the tubing is transferred from the standing valve to the traveling valve.
- The length of the rod string grows longer as the plunger tries to lift the weight of the liquid above and tries to overcome the friction and surface tension between the oil and tubing.
- As the weight of the column of liquid is lifted, there is less weight on the tubing, and the length of the tubing string gets shorter—that is, the bottom of the tubing string moves up the hole a short distance.
- The friction of the upward-moving oil also exerts a small lifting force on the tubing.
- *As the plunger moves downward,* the weight of the column of oil in the tubing is transferred from the traveling valve back to the standing valve.
- The length of the rod string grows shorter as it pushes back down against the freshly accumulated fluid.
- With the traveling valve open, the weight of the column of liquid rests on the standing valve and is exerted against the tubing string. This increased load causes the tubing string to become longer. The bottom of the tubing string moves downward, from a few inches to several feet, depending on the depth of the well, the weight of the column of fluid, and the size of the tubing.
- The downward movement of the tubing results in *over-traveling* of the pump—that is, the pump is moving away from the surface and accumulating additional fluid during the downstroke.

The action of the rods and tubing in response to these changing forces is called the *cyclic load factor*, and the up and down movement of the tubing in the hole is referred to as *breathing*. These changes in the length of the rod string and the tubing string can be computed so that the length of the surface stroke can be adjusted accordingly.

A-3. Problems Caused by the Cyclic Load Factor.

Several problems can result from the cyclic loading and breathing action of the rod string and tubing string. Some of these are:

- As the tubing and collars move up and down in the casing, holes may wear in the casing and cause a casing leak.
- The collars or tubing may wear to the point that the string begins leaking liquid from inside the tubing back into the casing, where it falls back to the bottom of the hole. In extreme situations the tubing string can separate. Wear is especially high when the tubing or collar is rubbing at the bends or *dog legs* in the casing that are a natural result of the drilling process.
- The stretching of the rods and shortening of the tubing results in a shorter relative stroke length inside the pump than the travel of the rod string at the surface. This results in lower pumping efficiency and reduced production. The lease pumper must pump the well longer to overcome this loss in pump stroke. For a shallow

marginal well, this is usually not a great problem because the typical well does not pump a full twenty-four hours per day.

A *tubing holddown* can be installed near the bottom of the tubing string to reduce the up and down movement at the bottom of the string. A tubing holddown is similar to a packer except that it does not have rubber to seal against the casing. Fluids may move freely by the holddown. To prevent movement in the upper area of the tubing string, it may be necessary to pull several thousand pounds of tension on the tubing string. As an illustration, a 10,000-foot well with 2-7/8-inch tubing may have a tension of 25,000 pounds pulled on it above the weight of the string. The installation of holddowns is routine in all deeper wells.

A-4. Pumping at the Wrong Speed.

Problems created by the cyclic load factor can also be compounded by pumping the unit at the wrong speed. On medium to deep wells, as the top rods begin moving downward at the surface, the pump traveling valve at the bottom is still moving up. The problem reverses when the top rod starts moving up and the pump traveling valve is still going down. This problem can become exaggerated if the pumping operation is not carefully planned so that the SPM, RPM, sheave diameter, and other factors are not carefully matched to the characteristics of the well, such as depth and fluid weight and viscosity. If the cyclic load factor is large—that is, there is a great deal of stretch in the rod and tubing strings and their travel relative to each other is out of synchronization—pumping efficiency can be greatly reduced. In such a case, increasing the number of strokes per minute may actually decrease the length of the stroke at the bottom of the hole. Although SPM has increased, the amount of fluid produced has decreased.

Most pump companies provide a service through which they will calculate the proper arrangement of the pump components based on the pumping conditions, such as the depth of the well, size of rods, length of stroke, and strokes per minute.

Such planning, when properly matched to the characteristics of the well, will help to ensure that mechanical lift is suitable for the lease. The remaining sections of this chapter discuss the operation and maintenance of mechanical lift systems, while other lift methods are discussed in the chapters that follow.