CHAPTER 1

Introduction

Contents

1.1 ARTIFICIAL LIFTING

Usually, oil wells in the early stages of their lives flow naturally to the surface and are called "flowing wells." Flowing production means that the pressure at the well bottom is sufficient to overcome the sum of pressure losses occurring along the flow path to the separator. When this criterion is not met, natural flow ends and the well dies. The two main reasons of a well's dying are:

- their flowing bottomhole pressure drops below the total pressure losses in the well, or
- pressure losses in the well become greater than the bottomhole pressure needed for moving the wellstream to the surface.

The first case occurs due to the removal of fluids from the underground reservoir; the second case involves an increasing flow resistance in the well. This can be caused by:

- an increase in the density of the flowing fluid as a result of decreased gas production, or
- various mechanical problems like a small tubing size, downhole restrictions, etc.

Artificial lifting methods are used to produce fluids from wells already dead or to increase the production rate from flowing wells; and several lifting

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mechanisms are available to choose from. One widely used type of artificial lift method uses a pump set below the liquid level in the well to increase the pressure so as to overcome the pressure losses occurring along the flow path. Other lifting methods use compressed gas, injected from the surface into the well tubing to help lifting of well fluids to the surface.

Although all artificial lift methods can be distinguished based on the previous basic mechanisms, the customary classification is somewhat different as discussed below.

1.1.1 Gas Lifting

All versions of gas lift use high-pressure natural gas injected in the wellstream at some downhole point. In continuous flow gas lift, a steady rate of gas is injected in the well tubing aerating the liquid and thus reducing the pressure losses occurring along the flow path. Due to the reduction of flowing mixture density, consequently flow resistance, the well's original bottomhole pressure becomes sufficient to move the gas/liquid mixture to the surface and the well starts to flow again. Therefore, continuous flow gas lifting can be considered as the continuation of flowing production.

In intermittent gas lift, gas is injected periodically into the tubing string whenever a sufficient length of liquid has accumulated at the well bottom. A relatively high volume of gas injected below the liquid column pushes that column to the surface as a slug. Gas injection is then interrupted until a new liquid slug of the proper column length builds up again. Production of well liquids, therefore, is done by cycles. The plunger-assisted version of intermittent gas lift uses a special free plunger traveling in the well tubing to separate the upward-moving liquid slug from the gas below it. These versions of gas lift physically displace the accumulated liquids from the well, a mechanism totally different from that of continuous flow gas lifting.

1.1.2 Pumping

Pumping involves the use of a downhole pump to increase the pressure in the well to overcome the sum of flowing pressure losses. It can be further classified using several different criteria—for example, the operational principle of the pump used. However, the generally accepted classification is based on the way the downhole pump is driven and distinguishes between rod and rodless pumping.

Rod pumping methods utilize a string of rods connecting the downhole pump to the surface driving mechanism which, depending on the type of pump used, makes an oscillating or rotating movement. The first kinds of pumps to be applied in water and oil wells were of the positive-displacement type requiring an alternating vertical movement to operate. The dominant and oldest type of rod pumping is walking-beam pumping, or simply called "sucker-rod pumping." It uses a positive-displacement plunger pump, and its most well-known surface feature is a pivoted walking beam.

The need for producing deeper and deeper wells with increased liquid volumes necessitated the evolution of long stroke sucker-rod pumping. Several different units were developed with the common features of using the same pumps and rod strings as in the case of beam-type units, but with substantially longer pump stroke lengths. The desired long strokes did not permit the use of a walking beam, and completely different surface driving mechanisms had to be invented. The basic types in this class are distinguished according to the type of surface drive used: pneumatic drive, hydraulic drive, or mechanical drive long-stroke pumping.

A newly emerged rod-pumping system uses a progressing cavity pump that requires the rod string to be rotated for its operation. This pump, like the plunger pumps used in other types of rod pumping systems, also works on the principle of positive displacement, but does not contain any valves.

Rodless pumping methods, as the name implies, do not have a rod string to operate the downhole pump from the surface. Accordingly, other means (besides mechanical) are used to drive the downhole pump, such as electric or hydraulic. A variety of pump types are utilized with rodless pumping including centrifugal, positive displacement, or hydraulic pumps. Electric submersible pumping (ESP) utilizes a submerged electrical motor driving a multistage centrifugal pump. Power is supplied to the motor by an electric cable run from the surface. Such units are ideally suited to produce high liquid volumes.

The other lifting systems in the rodless category all employ a high-pressure power fluid that is pumped down the hole. Hydraulic pumping was the first method developed; such units have a positive-displacement pump driven by a hydraulic engine, contained in one downhole unit. The engine or motor provides an alternating movement necessary to operate the pump section. The hydraulic turbine-driven pumping unit consists of a multistage turbine and a multistage centrifugal pump section connected in series. The turbine is supplied with power fluid from the surface and drives the centrifugal pump at high rotational speeds, which lifts well fluids to the surface.

Jet pumping, although it is a hydraulically driven method of fluid lifting, completely differs from the rodless pumping principles discussed so far. Its downhole equipment converts the energy of a high velocity jet stream into useful work to lift well fluids. The downhole unit of a jet pump installation is the only oil well pumping equipment known today containing no moving parts.

1.1.3 Comparison of Lift Methods

Although there are some other types of artificial lift known, their importance is negligible compared to those just mentioned. Thus, there is a multitude of choices available to an engineer when selecting the type of lift to be used. Although the use of many of those lifting mechanisms may be restricted or even ruled out by actual field conditions such as well depth, production rates desired, fluid properties, and so on, usually more than one lift system turns out to be technically feasible. It is then the production engineer's responsibility to select the type of lift that provides the most profitable way of producing the desired liquid volume from the given well(s). After a decision is made concerning the lifting method to be applied, a complete design of the installation for initial and future conditions should follow.

To provide a preliminary comparison of the available artificial lift methods, **Fig. 1.1** is presented where approximate maximum liquid production

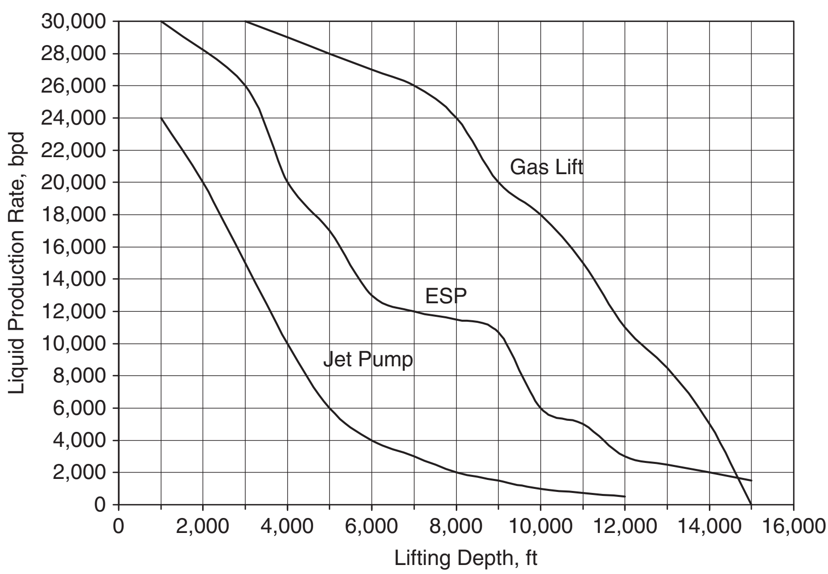

Fig. 1.1 Maximum liquid production rates vs lifting depth for various high-rate artificial lift methods.

rates of the different installations are given [1] in the function of lifting depth. The figure shows three lifting mechanisms capable of producing exceptionally high liquid rates: gas lifting, ESP (electrical submersible pumping) and jet pumping. As seen, gas lifting (continuous flow) can produce the greatest amounts of liquid from any depth. In all cases, lifting depth has a profound importance on the liquid volume lifted with well rates rapidly decreasing in deeper wells.

1.2 SHORT HISTORY OF ESP APPLICATIONS

Unlike most of the other artificial lift methods such as gas lifting or sucker-rod pumping, whose invention cannot be attributed to any person or any definite time, electrical submersible pumping was invented and developed by a Russian named **Armais Arutunoff** in the late 1910s [2]. In 1911, Arutunoff started the company **Russian Electrical Dynamo of Arutunoff** (its acronym **REDA** still being known all over the world) and developed the first electric motor that could be operated submersed in an oil well. To acquire funding for the development of his ideas, Arutunoff first emigrated to Germany in 1919, and then finally settled in the USA in 1923. The US Patent he received on the electrical submersible pump [3] was issued in 1926 and covered the principal features of this new artificial lift method. The first ESP installation was successfully operated in the El Dorado field in Kansas in 1926. Arutunoff moved to Bartlesville, Oklahoma, in 1928 where he started the Bart Manufacturing Co., later reorganized as REDA Pump Co. in 1930.

The first ESP units were driven by three-phase two-pole electric induction motors of $5^3/_8$ in or $7^1/_4$ in OD. The biggest motor was about 20 ft long and developed 105 HP. Directly above the motor a seal unit was attached whose main task was to prevent the leakage of well fluids into the motor. On top of the seal unit, a multistage centrifugal pump lifted well fluids to the surface. The complete ESP unit (motor, seal and pump) was run into the well on the bottom of the tubing string, electricity being supplied from the surface to the motor by a special three-conductor cable. Even today, these are the main components of electrical submersible pumping installations. After more than 80 years of operation, the company established by Arutunoff, who alone received 90 patents related to submersible equipment, is still one of the leading suppliers of ESP equipment to the world's petroleum industry.

From its conception, ESP units have excelled in lifting much greater liquid rates than most of the other types of artificial lift and found their best use in high rate on- and offshore applications. It is believed that today approximately 10% of the world's oil supply is produced with submersible pumping installations.

During its long history, ESP equipment underwent a continuous improvement. The first breakthrough came in the early 1950s when seal units (a.k.a. protectors) with mechanical seals on their shafts considerably increased ESP run lives because they provided a much better protection against leakage of well fluids into the motor. Production of gassy wells was always a problem and the use of simple gravitational (reverse-flow) gas separators did not solve the problem completely until the first rotary gas separator [4] was introduced in the early 1970s. Although the other components of the ESP unit have also evolved, the next revolutionary moment came when the first variable speed ESP unit was installed in August 1977 [5]. The variable speed drive (VSD) changes the frequency of the electric current driving the ESP motor and thus considerably modifies the head performance of the submersible pump. By properly setting the driving frequency, a very basic limitation of ESP units can be eliminated and the lifting capacity of the submersible pump can easily be modified to match the inflow performance of the well. Without a VSD unit, in wells with unknown liquid production capacities the ESP unit has to be exchanged with a unit better fitting the inflow to the well, which usually involves a costly workover operation.

Running and pulling of conventional ESP units involves the use of heavy workover units because the tubing string has to be moved into or out of the well. Reduction of the high workover costs can be accomplished if the ESP unit is run on a wire rope of the right mechanical strength. Cable suspended units, first appearing in the oil field in the late 1970s, became very popular for their advantageous features, especially in the offshore environment [6]. Similar advantages can be reached with coiled tubing (CT) conveyed ESP units, first installed in Alaskan fields in 1992 [7].

1.3 BASIC FEATURES OF ESP INSTALLATIONS

1.3.1 Applications

The first big-scale success for ESP installations occurred in the late 1920s when the Oklahoma City field was converted from beam pumping to submersible pumping. The ESP units could lift oil volumes of up to 1,000 bpd, an amount 2–3 times greater than beam pumping units were able to produce [2]. Early applications also showed their advantages in waterflood operations where increasing the liquid rates could greatly raise oil production.

Today, main applications include onshore waterflood operations (both liquid production and water injection), offshore production, and all other cases where electricity is available and large volumes have to be lifted. The usual range of liquid rates, in the typical installation depth range of 1,000 to 10,000 ft, is between 20,000 and 200 bpd, heavily decreasing with well depth, see **Fig. 1.1.** Extreme depth and liquid rate limits of present-day ESP units are around 15,000 ft and 30,000 bpd, respectively. One recent case study [8] reported a sustained liquid rate of 31,800 bpd from installations utilizing 2,000 HP tandem motors in wells with $5^1/_2$ in tubing and $9^5/_8$ in casing strings.

Special applications outside the petroleum industry, like production from water supply wells, can reach much greater liquid rates; one major manufacturer offers submersible pumps capable of 64,000 bpd maximum production rate.

1.3.2 Advantages, Limitations

General advantages of using ESP units can be summed up as follows, based on [9–11]:

- Ideally suited to produce high to extremely high liquid volumes from medium depths. Maximum rate is around 30,000 bpd from 1,000 ft.
- Energy efficiency is relatively high (around 50%) for systems producing over 1,000 bpd.
- Can be used in deviated wells without any problems.
- Requires low maintenance, provided the installation is properly designed and operated.
- Can be used in urban locations since surface equipment requires minimal space.
- Well suited to the offshore environment because of the low space requirements.
- Corrosion and scale treatments are relatively easy to perform.

General disadvantages are listed below:

- A reliable source of electric power of relatively high voltage must be available.
- The flexibility of ESP systems running on a constant electrical frequency is very low because the centrifugal pump's liquid producing capacity practically cannot be changed. Proper installation design based on accurate well inflow data and matching the unit's capacity to well

deliverability is crucial, otherwise costly workover operations are required to run a new unit in the well. The use of variable speed drives can eliminate most of these problems but at an extra cost.
- Free gas present at suction conditions deteriorates the submersible pump's efficiency and can even totally prevent liquid production. The use of gas separators or gas handlers is required if more than 5% of free gas enters the pump.
- Sand or abrasive materials in well fluids increase equipment wear. Special abrasion-resistant materials are available but increase capital costs.
- Repair of ESP equipment in oilfield conditions is difficult, faulty equipment must be sent to the manufacturer's repair shop.
- High well temperature is a limiting factor, standard equipment is limited to about 250°F, and use of special materials increases the temperature limit to 400°F.
- Production of high viscosity oils increases power requirements and reduces lift.
- Running and pulling costs are high because of the need for heavy workover rigs. Cable suspended or CT (coiled tubing) deployed ESP units reduce workover costs.

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