Artificial Lift Methods

2nd Edition

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Well Servicing and Workover, Lesson 5

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WELL SERVICING AND WORKOVER SERIES
Lesson 5

Artificial Lift Methods

Second Edition

By William Lane

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About the Author

William Lane has 35 years of experience in the oil and gas industry performing roles in engineering, manufacturing, global product line management, and artificial lift training. He has been directly involved with surface service equipment, completions, compression, artificial lift, and unconventional resources. He has been working with Weatherford International and the former EVI Oil Tools Ltd. for 18 years in various executive positions and is currently serving as the vice president of emerging technologies for Weatherford Artificial Lift Systems Inc.

Lane holds several U.S. patents, and in 2003 was the recipient of a Harts E&P Special Meritorious Award for Engineering Innovation. He holds a B.S. degree in Mechanical Engineering and an M.S. degree in Mechanical Engineering Design, both from the University of Texas at Arlington.

Units of Measurement

Throughout the world, two systems of measurement dominate: the English system and the metric system. Today, the United States is one of only a few countries that employ the English system.

The English system uses the pound as the unit of weight, the foot as the unit of length, and the gallon as the unit of capacity. In the English system, for example, 1 foot equals 12 inches, 1 yard equals 36 inches, and 1 mile equals 5,280 feet or 1,760 yards.

The metric system uses the gram as the unit of weight, the metre as the unit of length, and the litre as the unit of capacity. In the metric system, 1 metre equals 10 decimetres, 100 centimetres, or 1,000 millimetres. A kilometre equals 1,000 metres. The metric system, unlike the English system, uses a base of 10; thus, it is easy to convert from one unit to another. To convert from one unit to another in the English system, you must memorize or look up the values.

In the late 1970s, the Eleventh General Conference on Weights and Measures described and adopted the Systeme International (SI) d'Unites. Conference participants based the SI system on the metric system and designed it as an international standard of measurement.

The Well Servicing and Workover Series gives both English and SI units. And because the SI system employs the British spelling of many of the terms, the book follows those spelling rules as well. The unit of length, for example, is metre, not meter. (Note, however, that the unit of weight is gram, not gramme.)

To aid U.S. readers in making and understanding the conversion system, we include the table on the next page.

English-Units-to-SI-Units Conversion Factors

Quantity or Property	English Units	Multiply English Units By	To Obtain These SI Units
Length, depth, or height	inches (in.)	25.4	millimetres (mm)
		2.54	centimetres (cm)
	feet (ft)	0.3048	metres (m)
	yards (yd)	0.9144	metres (m)
	miles (mi)	1609.344	metres (m)
		1.61	kilometres (km)
Hole and pipe diameters, bit size	inches (in.)	25.4	millimetres (mm)
Drilling rate	feet per hour (ft/h)	0.3048	metres per hour (m/h)
Weight on bit	pounds (lb)	0.445	decanewtons (dN)
Nozzle size	32nds of an inch	0.8	millimetres (mm)
Volume	barrels (bbl)	0.159	cubic metres (m^3)
		159	litres (L)
	gallons per stroke (gal/stroke)	0.00379	cubic metres per stroke (m^3/stroke)
	ounces (oz)	29.57	millilitres (mL)
	cubic inches ($in.^3$)	16.387	cubic centimetres (cm^3)
	cubic feet (ft^3)	28.3169	litres (L)
		0.0283	cubic metres (m^3)
	quarts (qt)	0.9464	litres (L)
	gallons (gal)	3.7854	litres (L)
	gallons (gal)	0.00379	cubic metres (m^3)
	pounds per barrel (lb/bbl)	2.895	kilograms per cubic metre (kg/m^3)
	barrels per ton (bbl/tn)	0.175	cubic metres per tonne (m^3/t)
Pump output and flow rate	gallons per minute (gpm)	0.00379	cubic metres per minute (m^3/min)
	gallons per hour (gph)	0.00379	cubic metres per hour (m^3/h)
	barrels per stroke (bbl/stroke)	0.159	cubic metres per stroke (m^3/stroke)
	barrels per minute (bbl/min)	0.159	cubic metres per minute (m^3/min)
Pressure	pounds per square inch (psi)	6.895	kilopascals (kPa)
		0.006895	megapascals (MPa)
Temperature	degrees Fahrenheit (°F)	$\frac{°F - 32}{1.8}$	degrees Celsius (°C)
Mass (weight)	ounces (oz)	28.35	grams (g)
	pounds (lb)	453.59	grams (g)
		0.4536	kilograms (kg)
	tons (tn)	0.9072	tonnes (t)
	pounds per foot (lb/ft)	1.488	kilograms per metre (kg/m)
Mud weight	pounds per gallon (ppg)	119.82	kilograms per cubic metre (kg/m^3)
	pounds per cubic foot (lb/ft^3)	16.0	kilograms per cubic metre (kg/m^3)
Pressure gradient	pounds per square inch per foot (psi/ft)	22.621	kilopascals per metre (kPa/m)
Funnel viscosity	seconds per quart (s/qt)	1.057	seconds per litre (s/L)
Yield point	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Gel strength	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Filter cake thickness	32nds of an inch	0.8	millimetres (mm)
Power	horsepower (hp)	0.75	kilowatts (kW)
Area	square inches ($in.^2$)	6.45	square centimetres (cm^2)
	square feet (ft^2)	0.0929	square metres (m^2)
	square yards (yd^2)	0.8361	square metres (m^2)
	square miles (mi^2)	2.59	square kilometres (km^2)
	acre (ac)	0.40	hectare (ha)
Drilling line wear	ton-miles (tn•mi)	14.317	megajoules (MJ)
		1.459	tonne-kilometres (t•km)
Torque	foot-pounds (ft•lb)	1.3558	newton metres (N•m)

Artificial Lift Overview

In this chapter:

- How artificial-lift systems produce fluids
- Current lift technologies used on land and offshore
- Factors to consider when selecting a lift system
- Environmental and operator-discretionary factors

Ideally, a hydrocarbon-bearing reservoir should contain enough natural pressure to enable *fluids* to flow to the surface for several years without requiring external energy. Over time, however, energy in the formation will decline to the point that pressure and/or flow velocity will no longer be adequate to move fluids to the surface. When a well reaches this point in its lifecycle, fluids must be produced (or lifted) to the surface through artificial means.

Notable exceptions include wells completed in prolific *water drive* reservoirs where wells continue to flow water under natural reservoir energy after hydrocarbon production has ceased. Likewise, large *gas-cap reservoirs* can contain sufficient energy to produce much of the recoverable hydrocarbons without artificial lift. However, more often, wells require artificial lift at some point in their economic life.

Even gas wells typically require some sort of deliquification system to remove water. Water accumulating in the wellbore creates a back-pressure that limits gas inflow from the reservoir, so the water must continually or periodically be removed to allow for the free flow of gas.

Reciprocating Rod Lift

In this chapter:

- Typical applications of reciprocating rod systems
- Operating principles of a sucker rod pump
- Rod pump system design and components
- Types of surface rod pumping units
- Factors to consider when selecting and using rod string

The history of reciprocating rod lift is closely tied to the early oilwells that were established in 1859 by Edwin Drake in the small, rural community of Titusville, Pennsylvania. Commonly referred to as the Drake well, this earliest of drilling sites forever shaped industry and trade while advancing human mobility. Around 300 to 400 gallons (about 1,135 to 1,514 litres) were reportedly lifted from the site each day; however, the drilling process was expensive, tedious, and extremely dangerous.

The majority of artificial-lift systems in use are reciprocating rod lift systems.

Within ten years of the Drake well, conventional rod pumping was becoming increasingly popular. Early rod-pumping systems consisted of a standard cable tool drilling rig, placed in such a way that the walking beam could be used to operate the pump. Prior, rod-activated pumps had been used to produce *brine*. Similar to the pump illustrated in figure 1, they consisted primarily of a cylinder made up in the tubing string, a *standing valve* seated in the tubing string, a plunger, and *traveling valve*. It is likely that *flapper valves* were used rather than *ball valves*, which are depicted in the figure. Originally, the plunger was reciprocated in the cylinder by means of wooden sucker rods with wrought-iron end fittings for connections.

Electric Submersible Pumps

In this chapter:

- Typical applications of electric submersible pumps
- Operating principles for high volumes of fluids
- Key system components and how they function
- Basic ESP system design factors to consider

In 1916, Armias Arutunoff developed the first cylindrical multistage electric submersible pump (ESP) for dewatering mines and ships. He formed the Russian Electrical Dynamo of Arutunoff Company (REDA) and applied the technology to oilwells, first in Russia and then in Germany. Mr. Arutunoff immigrated to the United States and installed the first ESP in the Western Hemisphere in a Phillips Petroleum well in Kansas in 1928. By 1938, approximately 2% of artificially lifted oil in the United States was lifted by REDA pumps.

Today, ESPs have become the preferred lift technology for many pumping applications, from shallow dewatering of mines to high-volume offshore oil production. High-temperature systems have been developed to allow ESPs to pump in applications traditionally serviced only by rod pumping systems. Special gas-handling features have made it possible to use ESPs in some gaseous well applications. As a result, more capital is spent on procurement of ESP systems today than all other lift technologies combined.

Conventional Gas Lift

In this chapter:

- Typical applications of conventional gas-lift systems
- Distinctions between continuous and intermittent gas lift
- Key factors to consider when using gas lift
- Achieving maximum efficiency with a gas-lift system

Air lifting of water with a small amount of oil was first known to be used in the United States as early as 1846, but compressed air was reportedly used to lift water from wells in Germany as early as the eighteenth century. These systems operated initially in a very simple manner by induction of air to the bottom of the tubing and out into the casing. *Aeration* of the fluid in the casing-tubing annulus decreased the weight of the mixture to the extent that fluid would rise to the surface and flow out of the well. The process was sometimes reversed by injecting down the casing and producing through the tubing.

Plunger Lift

In this chapter:

- Typical applications of plunger lift
- Operating principles and functionality
- System components and their effectiveness
- Factors to consider when designing a plunger-lift system

Plunger lift is a method of lifting fluid by produced gas to drive a free-piston (plunger) from the lower end of the tubing string to the surface. This is done to remove accumulated fluid from the tubing string. Plunger lift is similar to intermittent gas lift in that it uses stored gas energy from the annulus or wellbore to periodically lift slugs of liquid, rather than lifting the entire column of fluid all at once.

The plunger lift overcomes two of the efficiency challenges of intermittent gas lift. First, the plunger acts as a mechanical interface seal between the slug of liquid that is lifted and the gas that moves the plunger and liquid. Thus, fluid fallback is greatly reduced, resulting in improved lifting efficiency. Second, the fluid is lifted using the energy of the formation rather than requiring pressurized injection gas energy from the surface. The result is the most cost efficient lift technology for low-volume applications (fig. 61).

Velocity Strings and Foam Lift

In this chapter:

- Typical applications of foam-lift technology
- Operating principles and the role of critical velocity
- Using surfactants to lower surface tension
- How system components work to extend well life

In a flowing gas well, liquids entrain in the gas and accumulate at the bottom of the well. This increases the bottomhole pressure (BHP) in the well and inhibits gas inflow. Also, accumulated liquids displace gas in the near-wellbore formation, reducing gas permeability and hindering gas migration to the wellbore. If flow velocities are sufficiently high, the flowing gas will continuously blow liquids out of the well to keep the well unloaded, or clear of liquids. However, at lower gas velocities liquids accumulate in the wellbore, slowing gas inflow. Eventually the entrained and accumulating liquids can increase BHP to the point that gas production ceases.

The term liquid loading refers to the accumulation of liquids in a wellbore that inhibits gas inflow. One way to prevent or relieve liquid loading is to enhance gas velocities; another way is to cause the liquid to foam so that it can be more easily displaced.

Flow velocities can be increased by reducing the cross-sectional flow area of the gas stream. This can be accomplished by flowing the well fluids through reduced diameter tubing (velocity string) or through the annulus around an inserted *dead string* of tubing. Gas flow velocities can also be increased by injecting gas to comingle with produced gas.

Foam lift is primarily a dewatering technology, although effective surfactants have been developed for hydrocarbons.

Hydraulic Lift

In this chapter:

- Typical applications of hydraulic lift
- Configurations of hydraulic-lift systems
- Principles of hydraulic jet and piston pumps
- Surface equipment required for hydraulic lift

In 1932, C.J. Coberly installed the first hydraulic piston pump in Inglewood, California as a solution to pumping oil without using a sucker rod string. Later, Coberly formed Kobe, Inc., and the company was the first to successfully use a hydraulic jet pump to produce an oilwell. Since then, jet pumps have been used to pump up to 35,000 barrels of well fluids per day. Hydraulic pumping represents one of the most flexible forms of artificial lift; it can often successfully produce wells in which other lift technologies have failed (fig. 71).

Hydraulic-pumping systems consist of four basic parts:

- Power-fluid conditioning and supply
- Surface power unit and hydraulic pump
- Piping to transfer the high-pressure power fluid to the subsurface pump
- Subsurface jet pump or piston pump (fig. 72)

The fluid-conditioning system cleans and prepares the power fluid, which is typically a produced well fluid, such as water or oil.

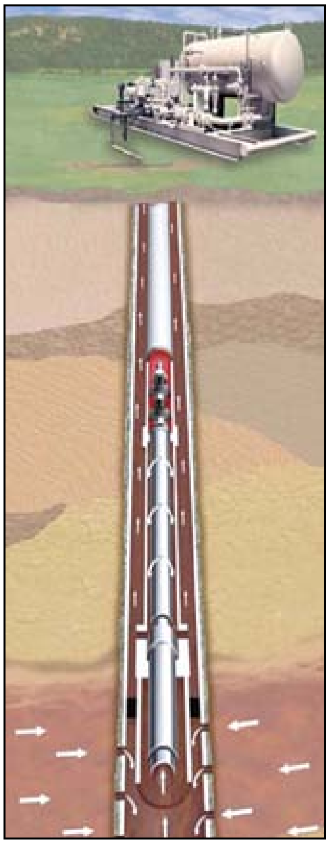
Courtesy of Weatherford International

Figure 71. Hydraulic-lift system

Production Optimization

In this chapter:

- Maximizing production throughout the life of a well
- Addressing factors that can hinder production
- How systems collect and transmit well data
- Key elements of a production-optimization system

The previous sections of this book all deal with selecting, designing, and effectively applying lift technologies based on assumptions about how the reservoir will deliver fluids. In reality, production always varies somewhat from what was expected because well conditions, inflow volumes, and fluid phases change over time.

The artificial-lift system should be adjusted as needed to match the inflow rates from the reservoir. As fluid production declines, the lift system pumping rate must be similarly reduced or the well might become pumped dry of fluids, causing damage to the lift systems and potentially to the reservoir. In other situations, improved reservoir management techniques can increase reservoir deliverability, but production might then be constrained by lift system performance. Until the lift system is adjusted to produce at the new deliverability rates, the lift system can cause an undetected bottleneck. Damage to lift systems and lost potential production from suboptimum lift performance are easily prevented but are often overlooked by manual surveillance practices.

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