OIL AND GAS PRODUCTION SERIES

Artificial Lift

Second Edition

The University of Texas at Austin
Petroleum Extension (PETEX™)

The PETEX™ Production Collection

Oil and Gas Production Series

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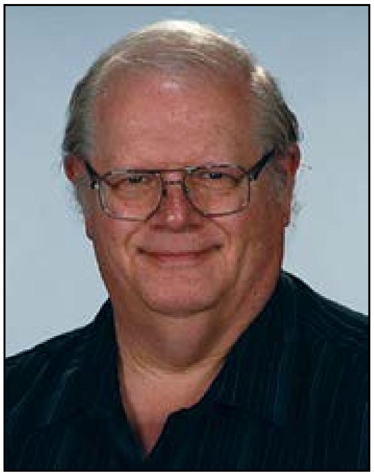
About the Author



Norman W. Hein, Jr. has worked in the upstream production side of the oil and gas industry for more than 38 years. Throughout his distinguished career, he has contributed his time, energy, and talent to a variety of assignments all over the world—ranging from jobs that required research, development, and testing to ventures that demanded his expertise in production engineering, manufacturing, land and offshore project management, industry standardization, and the principles of artificial lift.

Before establishing his own consulting company, Oil and Gas Optimization Specialists, Ltd. (OGOS) in 2003, Norman worked for Conoco and later Conoco Phillips. In 2010, he signed on with the sucker rod division of Norris Production Solutions (now, Dover Artificial Lift) and later served as Senior Advisor for CONSOL Energy in Canonsburg, PA. Currently, Norman is the president and general manager of OGOS where he is actively pursuing consulting, troubleshooting, and training opportunities.

A proven innovator, Norman holds 11 domestic patents and over 50 international patents. He has given more than 100 technical presentations and has taught courses on artificial lift, production operations, production chemicals, corrosion, and well/field optimization both at home and abroad.

Norman has written books on surface dynamometer card interpretation and authored two SPE Distinguished Author Series papers—one on artificial lift method selection and another on sucker rod lift field optimization. More recently, Norman authored a chapter on sucker rod lift for the latest edition of the SPE *Petroleum Engineering Handbook*.

Norman was a founding member of the Artificial Lift Research and Development Council (ALRDC) and currently serves on this organization's board of directors. He has been awarded the J.C. Slonneger Award from the Southwest Petroleum Short Course in Lubbock, TX, a Letter of Appreciation from ANSI/API for his leadership and contributions to the oil and gas industry, and the Certificate of Service from API. Norman holds a B.S. degree in Metallurgy with a minor in Manufacturing and a M.S. degree in Materials Science from the University of Illinois.

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 Oil and Gas Production 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)

Planning an Artificial Lift Program

In this chapter:

- Fundamental principles of artificial lift
- Design factors to consider
- Assessing and predicting reservoir performance
- PI and IPR curve methods
- Rate of outflow and reservoir recovery
- Minimizing downtime and maximizing production

In many cases, a well completed in a new *reservoir* will flow on its own with the energy for production coming from *pressure* in the reservoir. Over time, however, natural reservoir pressure will drop. The flow of oil and gas from the well will diminish and eventually cease to flow, leaving a great deal of recoverable hydrocarbons still in place. *Artificial lift* is any means of supplementing the reservoir's energy or furnishing the power necessary to bring that oil and gas to the surface. Thus, artificial lift increases production and results in increased recovery of reserves.

Installing artificial lift can be done at any time in the well's life, and there are many different artificial lift methods available to stimulate production. Each has its advantages and disadvantages that must be considered. Ultimately, the one that is selected should result in optimum production and recovery of reserves. However, there is no "best" method; each has a window of suitability depending on the characteristics of the well and the production capacity of the reservoir.

Sucker Rod Pumping

In this chapter:

- Basic principles of sucker rod lift
- Operation of a beam pumping unit
- Counterbalancing in a beam pumping unit
- Fluid pound and gas locking
- Operation of a pneumatic pump

As previously discussed, new reservoirs produce natural pressure, and it is this pressure that causes a well to flow for an extended period of time on its own. Eventually, however, this pressure subsides to such a degree that oil and gas do not reach the surface. When commercial amounts of oil and gas remain in the reservoir, an artificial lift system is employed to raise and amass these hydrocarbons. Multiple systems are available for this purpose, so several factors must be considered before one is selected and installed, including the characteristics of the reservoir and the inflow and outflow characteristics of the well. Apart from geological considerations and technical requirements, cost and the rate of return determine which lift system is selected and ultimately installed.

Sucker rod lift, or reciprocating rod lift, is the most widespread form of artificial lift. Used since the earliest days of the oil industry, *sucker rod pumps* are functionally the same as pumps used to lift water from wells in ancient China, Egypt, and the Roman Empire. Basically, a sucker rod pumping system consists of three parts: a bottomhole pump, rods to transmit power from the surface to the pump, and a surface pumping unit to furnish power to the rods in the form of *reciprocating motion* (fig. 13). The *beam pumping unit* illustrated is the most widely used type.

Gas and Plunger Lift

In this chapter:

- Principles of gas lift
- Process of continuous-flow gas lift
- Process of intermittent-flow gas lift
- Facts about chamber gas lift
- Operation of plunger lift

As previously discussed, sucker rod lift offers the oil and gas industry many benefits. These systems have the capacity to exhaust reservoirs of their hydrocarbons, and they can tolerate high-temperature or viscous oils with relative ease. Easy to maintain and notably reliable, this tried-and-true machinery is identified by its distinctive shape and admired for its ruggedness.

While this type of lift system can deplete many wells of their hydrocarbon accruals, it has proven far less effective in wells that are significantly curved. Its high-profile exterior, albeit familiar, is considered by passersby to be a major downside, especially in urban areas.

To service more populous areas, gas lift offers a less obtrusive and low-cost alternative to sucker rod pumping. The following sections examine the central components of these systems and illustrate how they are interconnected and function. As will be made clear, the decision to adopt this form of artificial lift is dependent on many of the same factors that influence the implementation or rejection of sucker rod pumping.

Use of plunger lift, another option for bringing fluid to the surface through artificial means, has expanded over the years, increasing the productivity of some wells many times over. An examination of this system's essential components and related processes follows.

Hydraulic Pumping

In this chapter:

- Basic operation of a hydraulic pump
- Features of hydraulic pumping units
- Facts about power-oil pumps
- Open and closed power-oil systems
- Operation of a hydraulic jet pump

As previously discussed, gas lift and plunger lift systems are known for their flexibility and economy. Gas lift is cost-effective and easy to operate, and the downhole equipment associated with it is fairly inexpensive. High production volumes can be obtained using gas lift, and such systems perform well even under adverse conditions or in crooked holes. Likewise, plunger lift, with its low profile, can help even highly-deviated wells produce more efficiently. Neither lift system, however, is flawless nor the most appropriate in all instances. Instead, hydraulic pumping, which has also proven to be adaptable in the field, might be a viable option.

C. J. Coberly of Kobe, Inc. first introduced hydraulic pumping to the oil industry in the early 1930s. The hydraulic piston pump used in this system is similar to the pump used in sucker rod pumping. It operates by a directly coupled hydraulic engine that is powered by a high-pressure fluid (either oil or water, up to 6,000 psi), which is pumped from the surface. The following sections take a closer look at the evolution of hydraulic pumping systems.

Electric Submersible Pumping

In this chapter:

- Aspects of conventional ESP installations
- Bottomhole assembly and surface equipment
- Application factors to keep in mind
- Use and operation in waterflood projects
- Layout of cable-suspended submersible pumps

As previously discussed, a hydraulic pumping system, like gas lift and plunger lift, might prove to be the best choice, depending on the location of the production site and the curvature of the well. Highly adaptable and easy to install, these inconspicuous machineries have the potential to yield fluid fairly efficiently regardless of depth and volume restrictions, especially when compared to sucker rod pumps.

Abrasive materials, such as sand, however, can plague hydraulic pumping systems, and unlike gas lift, they are impacted more so by the effects of corrosion. If corrosion is anticipated, electric submersible pumping offers another possibility for improving well production.

The electric submersible *multistage centrifugal pump* was introduced to the oil industry as a means of artificial lift by the Reda Pump Company in the late 1920s. Since that time, several other companies have developed electric submersible pumps, often called ESPs, for oil field use. This type of pump is now available in a large number of sizes, capacities, and operating voltages. In a conventional installation, the pump assembly and an electric motor are run into the well on the production tubing. Electric power is conducted to the assembly by a cable attached to the tubing (fig. 42).

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