SECTION 9.17
OIL WELLS

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ARTIFICIAL LIFT OF OIL WELLS

Oil wells can range in depth from approximately 200 ft (60 m) to more than 20,000 ft (6000 m). They require pumps that are unique in their configuration. About 90% of pumping oil wells are equipped with either 2-in (50.8-mm) or $2\frac{7}{16}$ in (61.9-mm) ID tubing. Sucker rod pumps, hydraulic reciprocating pumps, or hydraulic jet pumps that must run inside this tubing cannot have their outside diameters exceed $1\frac{7}{8}$ in (47.6 mm) or $2\frac{5}{16}$ in (58.7 mm). These pumps are installed as close as possible to the bottom in order to achieve the maximum possible drawdown of fluid in the well. The output pressure required of the pump varies directly with the depth that the fluid must be lifted. For example, to compensate for the lift required and the fluid friction in the tubing, a 10,000-ft (3049-m) well might require a 4000-lb/in^2 (276-bar°) pump.

In a newly discovered field, wells will usually flow of their own accord and require no artificial lift. The volume from these wells is controlled by holding back pressure at the wellhead with a choke. The annulus between the production tubing and the oil well casing is closed off at the wellhead; thus all of the gas produced by the well flows up the production tubing with the oil. When the bottom hole pressure is no longer adequate to produce the well by natural flow, some form of artificial lift must be installed. This can be a sucker rod pump, a subsurface hydraulic reciprocating pump, a subsurface hydraulic jet pump, an electric submersible centrifugal pump, or a gas lift. The sucker rod pump is by far the most common form of artificial lift. More than 80% of the wells that must be artificially lifted are pumped with sucker rod pumps.

°1 bar = 10^5 Pa.

THE SUCKER ROD PUMPING SYSTEM

The sucker rod pumping system consists of a prime mover, a pumping unit, a polished rod with a stuffing box to seal off the pumped fluid pressure at the surface of the well, and a sucker rod string to transmit the reciprocating movement from the pumping unit to the sucker rod pump. The pumping unit is the mechanism that converts the rotary movement of the prime mover to the reciprocating movement needed to power the sucker rod pump. The sucker rod string consists of individual sucker rods of 25- or 30-ft (7.6- or 9.1-m) lengths that are connected with couplings when they are lowered into the well. This total length of rods connects the surface polished rod to the pump at the bottom and is called the sucker rod string. The complete sucker rod pumping system is illustrated in Figure 1.

The operation of a sucker rod pump is illustrated in Figure 2. The pump is submerged in fluid near the bottom of the oil well. As the sucker rod string and plunger make an upstroke, fluid from the well bore flows past the standing valve into the pump barrel. Also on this upstroke, the traveling valve is closed and the fluid above the plunger is pumped up the annulus between the sucker rod string and the tubing string. On the downstroke, the traveling valve is open and the standing valve is closed. The fluid in the pumping chamber between the traveling valve and standing valve is displaced into the annulus between the tubing and the sucker rod string above the plunger. The fluid in the annulus is lifted toward the surface only on the upstroke.

The Sucker Rod Pump The principal parts of the sucker rod pump are the barrel, plunger, traveling valve, and standing valve. These are seen in a cutaway section in Figure 3. In shallow wells relatively free of sand, soft-packed plungers are frequently used. These have a number of fabric rings or cups that are expanded by the pumping pressure to a close fit with the barrel. In deep wells or in hard-to-pump shallow wells, the precision-fit metal barrel and plunger as shown in Figure 3 are used. The most common precision barrel is made from steel tubing with a case-hardened or induction-hardened inside wear surface. The inside diameter of the barrel is honed to the nominal bore size with a tolerance of ±0.001 in (0.025 mm). Premium barrels are chrome-plated on the inside diameter to a thickness of 0.003 in (0.076 mm) per side. Material for these barrels may be carbon or stainless steel, brass or Monel. The brass or Monel tubes are used when hydrogen sulfide, carbon dioxide, and brine mixed with produced fluid create an extremely corrosive condition. More common barrel lengths range from 5 to 24 ft (1.5 to 7.3 m), but longer lengths are available for use with very long-stroke surface units.

There are several kinds of plungers. A chrome-plated one-piece plunger or a plunger made of hard cast alloy iron sections assembled over a steel plunger tube is usually used with the precision hardened steel barrel. A plunger that is hard-faced with a nickel-based spray metal material is usually used with the chrome-lined barrel, although the cast plunger can also be used there. Plungers range from 2 to 6 ft (0.6 to 1.8 m) in length, depending on the depth of the well. These plungers are all ground to a precision tolerance of + 0.0000, −0.0005 in (+0.000, −0.013 mm). The diametral fit between the inside of the barrel and the outside of the plunger ranges from 0.002 to 0.005 in (0.05 to 0.13 mm), depending on the quality of the well fluid and the diameter and length of the plunger.

The traveling valve and standing valve of the pump are simple ball-and-seat check valves. Type 440 hardened stainless steel materials are the most common, but in corrosive wells, a cobalt-chromium-tungsten alloy is frequently used, and in very abrasive wells tungsten carbide seats and balls are used.

Sucker Rods Sucker rods are manufactured from carbon or low-alloy steel. Table 1 lists the properties of the grades of rod used most frequently. Most sucker rods are manufactured in 25-ft (7.62-m) lengths, but a few areas use 30-ft (9.14-m) lengths. Both ends of the rods are upset* and externally threaded (Figure 4). The upset ends also have a square for wrenching. Internally threaded couplings are used for connecting rods to make the

*In oil field terminology, an upset is an enlarged portion formed on the end of the rod by forging. This allows for a joint that is stronger than the body of the rod.

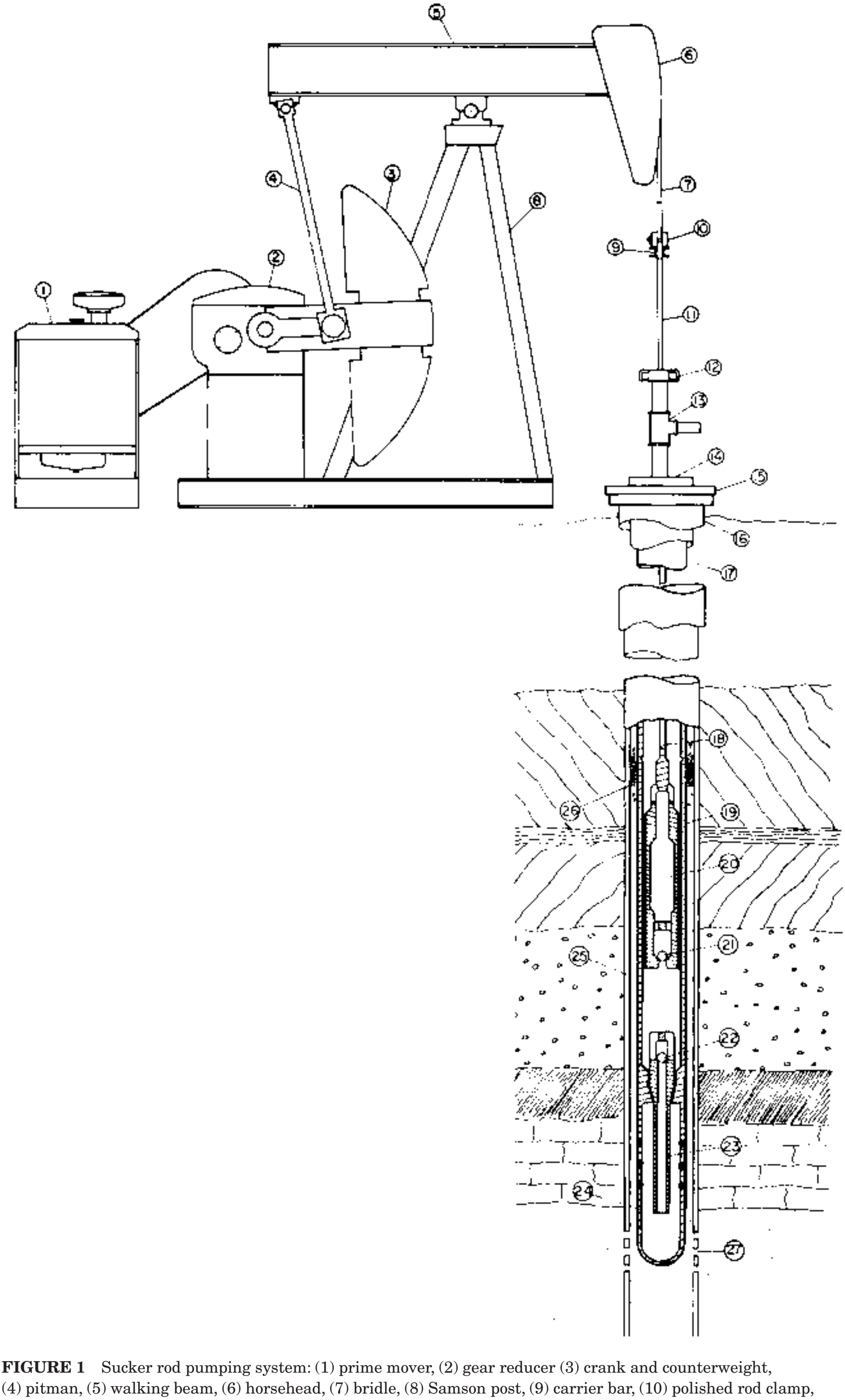

FIGURE 1 Sucker rod pumping system: (1) prime mover, (2) gear reducer (3) crank and counterweight, (4) pitman, (5) walking beam, (6) horsehead, (7) bridle, (8) Samson post, (9) carrier bar, (10) polished rod clamp, (11) polished rod, (12) stuffing box, (13) pumping tee, (14) tubing ring, (15) casing head, (16) casing surface string, (17) tubing string, (18) sucker rod, (19) pump barrel, (20) pump plunger, (21) traveling valve, (22) standing valve, (23) mosquito bill, (24) gas anchor, (25) casing oil string, (26) fluid level, (27) casing perforations (National Supply)

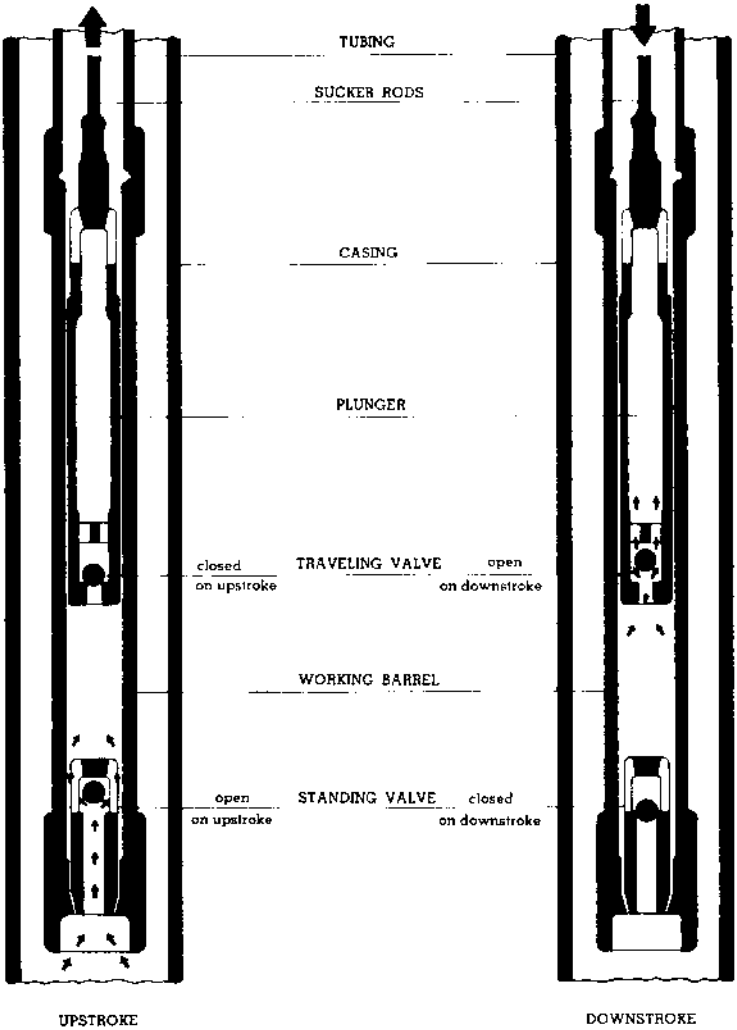

FIGURE 2 Operation of a tubing pump

TABLE 1 Mechanical properties of sucker rods

API class	AISI steel	Yield point, 1000 lb/in² (MPa)	Tensile strength, 1000 lb/in² (MPa)	Brinell hardness	Heat treatment
C	1036	60–75 (414–517)	90–105 (621–724)	190–205	Normalized
M	4621	68–80 (469–552)	85–100 (586–689)	175–207	Normalized and tempered
D	4142	100–115 (689–793)	115–140 (793–965)	240–280	Normalized and tempered

FIGURE 3 Sucker rod pump

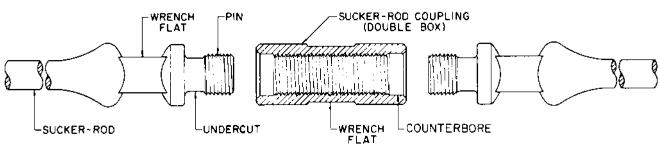

FIGURE 4 A typical sucker rod joint (API)

TABLE 2 Sucker rod data

Rod size, in (mm)	Pin size, in (mm)	Coupling OD, in (mm)	Cross-sectional area, in^2 (mm^2)	Dry weight, lb/ft (kg/m)	Stretch factor C, USCS[a] (SI)[b]
$\frac{5}{8}$ (15.88)	$\frac{15}{16}$ (23.81)	$1\frac{5}{8}$ (41.28)	0.307 (198)	1.15 (1.71)	1.322 (24.76)
$\frac{3}{4}$ (19.05)	$1\frac{1}{16}$ (26.99)	$1\frac{13}{16}$ (46.04)	0.442 (285)	1.63 (2.43)	0.919 (17.21)
$\frac{7}{8}$ (22.22)	$1\frac{3}{16}$ (30.16)	$2\frac{3}{16}$ (55.66)	0.601 (388)	2.18 (3.25)	0.676 (12.66)
1 (25.40)	$1\frac{3}{8}$ (34.92)	$2\frac{3}{8}$ (60.32)	0.785 (507)	2.94 (4.38)	0.517 (9.68)

[a]in/1000 ft · 1000 lb load
[b]mm/km · kN load

sucker rod string. Maximum design stress for sucker rods is between 30,000 and 40,000 lb/in^2 (207 and 276 MPa), depending on the metallurgy of the rod and the corrosive environment of the well. Useful data for designing sucker rod strings are shown in Table 2.

TABLE 3 Maximum rating of standard pumping units

Torque, in · lb (N · m)	Stroke length, in (m)	Structure capacity, lb (kN)	Design spm[a]
6,400 (8,677)	16 (0.406)	3,200 (14.23)	25
10,000 (13,560)	20 (0.508)	4,000 (17.79)	25
16,000 (21,690)	24 (0.610)	5,300 (23.58)	25
25,000 (33,800)	30 (0.762)	6,700 (29.80)	24
40,000 (54,230)	36 (0.914)	8,900 (39.59)	22
57,000 (77,280)	42 (1.07)	10,900 (48.49)	20
80,000 (108,400)	48 (1.22)	13,300 (59.16)	19
114,000 (154,600)	54 (1.37)	16,900 (75.17)	18
160,000 (216,900)	64 (1.63)	20,000 (88.96)	17
228,000 (309,000)	74 (1.88)	24,600 (109.4)	15
320,000 (433,900)	120 (3.05)	25,600 (113.9)	12
456,000 (618,300)	144 (3.66)	30,400 (135.2)	11
640,000 (867,700)	168 (4.27)	35,600 (158.4)	10
912,000 (1,237,000)	192 (4.88)	42,700 (189.9)	9

[a]Design spm (strokes per minute) is based on a Mills impulse load of 0.25 with a maximum spm of 25. This cycle rate may be exceeded; however, the values given here are considered good design practice.

Design of a single-size string for use in wells of shallow to moderate depth is a straightforward calculation and the tables and formulas included here are sufficient. In deeper wells, tapered* strings of rods are used, frequently 1, $\frac{7}{8}$, and $\frac{3}{4}$ in (25.4, 22.2, and 19.0 mm). Various methods are used for calculating the proper taper, but so many variables are involved that computer programs are frequently used to provide the total system design.

Surface Pumping Units Rating standards of beam pumping units have been established by the American Petroleum Institute (API). There are fourteen gear reducer torque ratings established, and these can be combined with various structures and a variety of stroke lengths to supply a pumping unit matched to virtually any well condition. Table 3 shows these torque ratings, the maximum stroke length, and the maximum structure capacity of standard units.

Pumping Installation Calculations The pump bore (ID of the pump barrel) is selected based on the quantity of fluid to be produced. A trial calculation is made to select a pump bore and a pumping unit stroke length that will produce the required volume of fluid. A volume calculation at 100% efficiency is performed using the bore factor from Table 4 and the stroke length and design strokes-per-minute value shown in Table 3. This is multiplied by 0.7 to correct for anticipated pump efficiency under average well conditions.

WEIGHT OF FLUID ON PLUNGER The trial calculation continues with the weight of the fluid on the plunger. Freshwater exerts a pressure of 0.433 lb/in^2 per vertical foot (9.79 kPa per vertical meter). The weight of the fluid on the plunger can be calculated with the formula

in USCS units $$W_f = 0.433\, A_p D(\text{sp. gr.})$$

in SI units $$W_f = 0.00979\, A_p D(\text{sp. gr.})$$

*When the sucker rod string is made up of several shorter strings, each of a different diameter, the total string is called tapered because the smallest-diameter strings are at the bottom and the largest at the top. This is done to reduce the total weight and to maintain approximately the same stress levels top to bottom.

TABLE 4 Sucker rod pump data

Pump bore, in (mm)	Plunger area, in^2 (mm^2)	Bore factor, USCS[a] (SI)[b]
$1\frac{1}{16}$ (26.99)	0.887 (572.1)	0.132 (0.826)
$1\frac{1}{4}$ (31.75)	1.227 (791.7)	0.182 (1.139)
$1\frac{1}{2}$ (38.10)	1.767 (1140.)	0.262 (1.639)
$1\frac{3}{4}$ (44.45)	2.405 (1552.)	0.357 (2.234)
2 (50.80)	3.142 (2027.)	0.466 (2.917)
$2\frac{1}{4}$ (57.15)	3.976 (2565.)	0.590 (3.691)
$2\frac{1}{2}$ (63.50)	4.909 (3167.)	0.728 (4.555)
$2\frac{3}{4}$ (69.85)	5.940 (3832.)	0.881 (5.512)
$3\frac{1}{4}$ (82.55)	8.296 (5352.)	1.231 (7.702)
$3\frac{3}{4}$ (95.75)	11.045 (7126.)	1.639 (10.255)

[a]Bore factor × stroke length in inches × spm = barrels/day (42-gal oil barrels).
[b]Bore factor × stroke length in meters × spm = cubic meters/day.

where W_f = weight (force) of fluid on plunger, lb (N)
A_p = area of plunger (Table 4), in^2 (mm^2)
D = fluid lift, distance from fluid level while pump is operating to ground surface, ft (m)
sp. gr. = specific gravity of fluid pumped, ratio of density of fluid to density of water at 60°F (16°C)

WET WEIGHT OF RODS The next calculation is the weight of the rods. The dry weight (force) of the rods Wr in pounds is computed by multiplying the weight (force) per foot of the rods (Table 2) by the length of the rods. This weight (force) in newtons is kilograms per meter times the acceleration of gravity (9.807 m/s^2) times the length of the rod. Because the rods have buoyancy when immersed in a fluid, their wet weight (force) W_w can be calculated with the formula

$$W_w = W_r\,(1 - 0.128 \text{ sp. gr.})$$

DEAD WEIGHT OF RODS AND FLUID This value is needed in subsequent calculations. It is the weight (force) of fluid on the plunger plus the wet weight of the rods:

$$W_{df} = W_f + W_w$$

IMPULSE LOAD The acceleration due to the reciprocating motion of the rods causes additional stresses in the sucker rod string. Twice during each stroke,° the rods are stopped and their motion reversed as they follow a sinusoidal acceleration pattern provided by the pumping unit. The resulting impulse load can be approximated using the Mills impulse load formula:

in USCS units
$$I = \frac{L\,(\text{spm})^2 W_r}{70{,}000}$$

in SI units
$$I = \frac{L\,(\text{spm})^2 W_r}{1780}$$

°In oil field terminology, a stroke is defined as the complete up and down cycle of the plunger. Distance traveled in one direction is stroke length.

where I = impulse load, lb (N)
L = length of polished rod stroke, in (m)
spm = strokes per minute
W_r = dry weight (force) of rods, lb (N)

PEAK POLISHED ROD LOAD The peak polished rod load P is

$$P = W_{df} + I$$

This peak polished rod load is used in final sizing of the surface pumping unit. If a single size of rod is used, P divided by the cross-sectional area of the rod gives the maximum rod stress. In a tapered string of reds, P divided by the cross-sectional area of the top rod will also approximate the maximum rod stress unless the rod string design is such that the rod under maximum stress is not at the top but lower in the string.

MINIMUM POLISHED ROD LOAD In addition to the peak polished rod load, a minimum polished rod load is also needed to determine the peak torque on the gearbox of the surface pumping unit. The minimum polished rod load P_m is

$$P_m = W_{df} - I$$

LOAD RANGE Load range P_r is

$$P_r = P - P_m$$

PEAK TORQUE The work transmitted from the prime mover through the gear reducer and crank applies a torque to the gears. Gear reducers are rated by the peak torque they can carry on a continuous basis. The peak torque T in inch-pounds (newton-meters) is proportional to the load range and may be calculated from the formula

$$T = 0.25 P_r L$$

The calculated peak torque must be lower than the torque rating, and the calculated peak polished rod load must be lower than the structure capacity rating of the unit selected (Table 3).

POLISHED ROD POWER The polished rod power P_{pr} in horsepower (kilowatts) can be calculated from the formula

in USCS $$P_{pr} = \frac{L\,(\text{spm})^2 P_r}{750{,}000}$$

in SI units $$P_{pr} = \frac{L\,(\text{spm})^2 P_r}{113{,}600}$$

Because the polished rod power calculation does not take friction into account, the prime mover selected should have at least double the power of the calculated figure.

PLUNGER OVERTRAVEL In accurately calculating pump displacement, it is necessary to calculate the actual plunger stroke, which is not the same as the polished rod stroke. The plunger gains stroke from overtravel. Long strings of rods are elastic and capable of stretching several feet. When the pumping unit stops the polished rod at the bottom of the surface stroke, the plunger continues to move downward because of inertia. This plunger overtravel OT in inches (meters) can be calculated from the formula

TABLE 5 External upset tubing data

Tubing size, in (mm)	Actual ID, in (mm)	Weight T&C,[a] lb/ft (kg/m)	Upset OD, in (mm)	Collar OD, in (mm)	Shrink factor *K* USCS (SI)
$2\frac{3}{8}$	1.995	4.63	2.594	3.063	0.313
(60.32)	(50.67)	(6.89)	(65.89)	(77.80)	(5.86)
$2\frac{7}{8}$	2.441	6.44	3.094	3.668	0.224
(73.02)	(62.00)	(9.58)	(78.59)	(93.17)	(4.20)
$3\frac{1}{2}$	2.992	9.27	3.750	4.500	0.151
(88.90)	(76.00)	(13.80)	(95.25)	(114.30)	(2.83)

[a]Threaded and coupled

in USCS units $$OT = \frac{(R_t \times \text{spm})^2 L}{50{,}000}$$

in SI units $$OT = \frac{(R_t \times \text{spm})^2 L}{4645}$$

where R_t is the total length of rod string in 1000 feet (kilometers).

SUCKER ROD STRETCH, TUBING SHRINK The sucker rod stretch starts when the plunger starts its upstroke and the fluid load is transferred from the tubing string to the sucker rod string. This occurs when the standing valve opens and the traveling valve closes. As the sucker rod string lengthens, the tubing string shortens. Both result in a stroke loss. The stroke loss due to rod stretch is shown in Table 2 as factor *C,* and the stroke loss due to tubing shrink is shown in Table 5 as factor *K.* Both are in inches per 1000 feet per 1000 pounds load (millimeters per kilometer per kilonewton).

NET PLUNGER STROKE The formula below illustrates a method of computing the net plunger stroke for a tapered string of 1-, $\frac{7}{8}$- and $\frac{3}{4}$-in (25.4-, 22.2- and 19.0-mm) rods with the tubing suspended freely. If the tubing is anchored to the well casing near the pump, the KR_t factor will be zero.

In USCS units $$L_p = L + OT - (CR_1 + CR_2 + CR_3 + KR_t)W_f \times 10^{-3}$$

In SI units $$L_p = L + OT - (CR_1 + CR_2 + CR_3 + KR_t)W_f \times 10^{-6}$$

where L_p = net plunger stroke, in (m)
R_1 = length of $\frac{3}{4}$-in (19.0-mm) rods, 1000 ft (km)
R_2 = length of $\frac{7}{8}$-in (22.2-mm) rods, 1000 ft (km)
R_3 = length of 1-in (25.4-mm) rods, 1000 ft (km)
R_t = length of tubing string, 1000 ft (km)

For a single-size rod string, zero values are assigned to the sizes not used. The pump displacement can now be calculated with the formula

in USCS units, $$\text{Barrels/day} = L_p \times \text{bore factor} \times \text{spm} \times 0.8$$

in SI units $$\text{Cubic meters/day} = L_p \times \text{bore factor} \times \text{spm} \times 0.8$$

The 0.8 factor assumes an 80% pump volumetric efficiency after correcting for sucker rod stretch and plunger overtravel. A lower efficiency should be assumed if the well is known to be gassy. If the pump displacement is more than required and the torque and structure capacity ratings of the unit are not exceeded, the calculations should be repeated using the next smaller size unit.

COUNTERBALANCE The pumping unit is supplied with a counterbalance in order to load the prime mover equally on the upstroke and the downstroke. The counterweights balance out the wet weight of the rods and half the weight of the fluid. All of the work in lifting is done on the upstroke. The energy stored in the counterweights during the downstroke supplies about half of the energy required for lifting the fluid. Because it lifted no fluid on the downstroke, the prime mover expends its energy lifting the unbalanced portion of the counterbalance load. Counterbalance effect CB is

$$CB = W_w + 1/2\, W_f$$

The pumping unit pictured in Figure 1 is known as a beam pumping unit. These are most common, but there are other types. One is a hydraulic surface unit, where a cylinder is set directly over the wellhead and a piston provides the reciprocating motion of the rods. These use commercial hydraulic pumps and control valves to supply the hydraulic power to the piston.

As shown in Table 3, standard sizes of beam pumping units have stroke lengths ranging from a little more than 1 ft (0.3 m) to a maximum of 16 ft (4.9 m). Recently a number of units have been marketed that permit stroke lengths up to 40 ft (12 m). The long stroke improves pump efficiency, prolongs sucker rod life, and reduces energy requirement. The unit pictured in Figure 5 uses wire line wound and unwound on a reversible drum to supply the reciprocating motion.

SUBSURFACE HYDRAULIC PUMPING SYSTEM

A complete hydraulic system consists of a fluid cleaning system, a power pump (usually a triplex), surface controls, a subsurface hydraulic pump, and tubing connecting the surface power pump to the subsurface pump. (See Section 3.1 for a complete description of power pumps.) Figure 6 is a schematic drawing of a complete multiple-well hydraulic system.

Because the pressurized power fluid supplies the energy needed to pump the well, the heavy sucker rod string and the heavy structure of the pumping unit required with the sucker rod pump are eliminated. Therefore, the hydraulic system can produce larger volumes of fluid from greater depths than the sucker rod pump.

The subsurface pump can be either a reciprocating piston pump or a jet pump. Both are usually made to be interchangeable in the same subsurface installation. Both pumps are

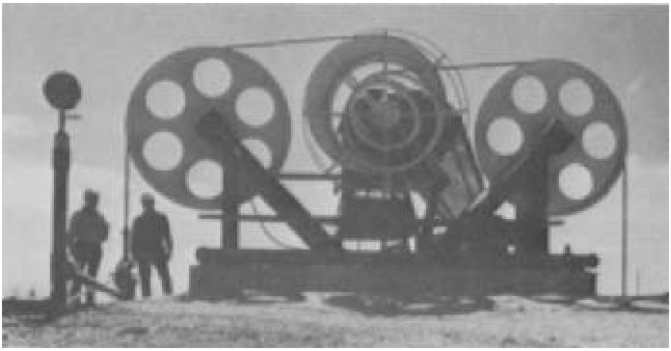

FIGURE 5 Winch pumping unit (Bethlehem Steel)

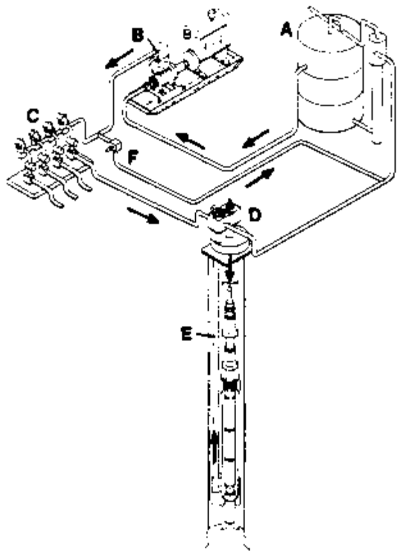

FIGURE 6 Multiple-well hydraulic installation: (A) power fluid tank, (B) triplex pump, (C) manifold, (D) wellhead, (E) tubing, (F) bypass valve (Kobe)

made in what is called the free pump configuration, which means that the pump assembly can be pumped down into the well or pumped out of it by the same surface power fluid system that powers the pump during normal operation with the pump on the bottom. The free pump feature gives the hydraulic pump a distinct servicing advantage over the sucker rod pump, which requires a mast or derrick over the well and a pulling unit to pull the rods one or two at a time when the pump needs servicing.

There are two basic types of hydraulic installations for the free pump: parallel free and casing free. Both result in a U-tube arrangement in which one leg of the U tube delivers the power fluid to the pump at the bottom and the other leg directs spent power fluid plus production back up to the surface. In the parallel free system, two parallel tubing strings* make up the U tube, and both are lowered into the well casing. In the casing free system, only one string is lowered into the well, and the annulus between this tubing and the well casing acts as the second leg of the U tube. Figure 7a illustrates installing a hydraulic pump in a parallel-free installation. A standing valve closes the bottom of the U tube, and the two strings are filled with fluid. The pump is inserted into the power fluid string, which is then securely capped, and the four-way valve is set to pump power fluid down the power fluid tubing. When the hydraulic pump reaches the bottom, a tapered bottom plug engages a seat on the standing valve and forms a pressure-tight seal. At the same time, an elastomer seal at the top of the pump enters a seal that now forces power fluid into the hydraulic pump (Figure 7b*)* to start it pumping (as described later). When it is desired to retrieve the pump to replace worn parts, the position of the four-way valve is reversed and power fluid is directed down the production tubing (Figure 7c*.)* The standing valve closes, the pump is unseated, and the circulation of fluid carries the pump to the surface, where it latches into the cap. The pressure is bled off from the U tube, and the wellhead cap with the worn pump is removed from the well.

*Individual joints of tubing coupled together to reach from the wellhead to the subsurface pump are called tubing strings.

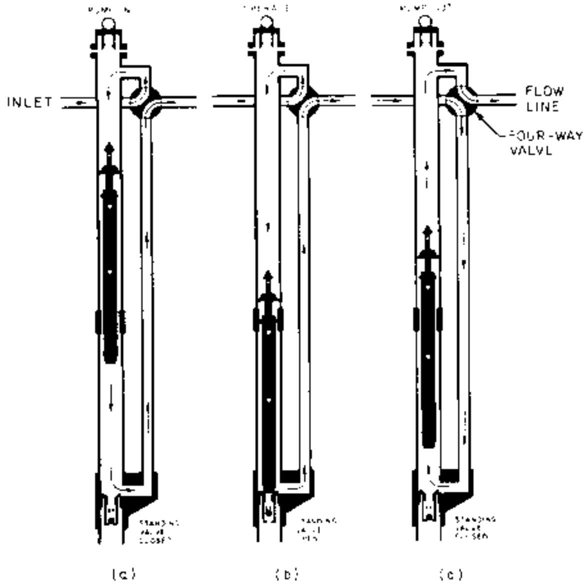

FIGURE 7A through C Hydraulic parallel free pump installation

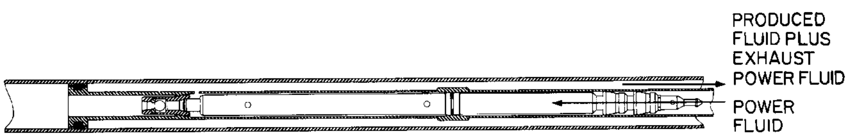

FIGURE 8 Casing free installation

The casing free installation (Figure 8) employs a packer that anchors and seals the tubing to the casing just below the pump assembly. The annulus between the tubing and casing above the packer takes the place of the production string in the parallel free installation. In operation, the power fluid is pumped down the power fluid string as before, but the mixture of exhaust power fluid plus production is returned to the surface in the tubing casing annulus. The annulus below the standing valve is at pump suction pressure. The casing free hydraulic pump installation is more economical because it requires only one string of tubing. It also has the advantage that the return fluid passage up the annulus is very large and fluid frictional losses are very low.

Natural gas separates from the crude oil as it enters the well bore. In the parallel free installation, this gas rises to the surface in the annulus between the tubing strings and the casing, entering the flow line with the produced fluid at the wellhead. In the casing free installation, however, this annulus is used to return the liquid discharged from the pump, and all of the produced gas must be pumped with the produced liquid. The hydraulic pump is not very efficient in pumping gas. Therefore, in gassy wells, the pump efficiencies for the casing free system will be lower.

Both the reciprocating hydraulic pump and the jet pump are designed to operate on fluid from the well. Either crude oil or water may be used as the power fluid. Sand particles and other abrasives contained in the produced fluid are removed either by gravity separation in surface settling tanks or by centrifugal force in cyclone separators. The cleaned

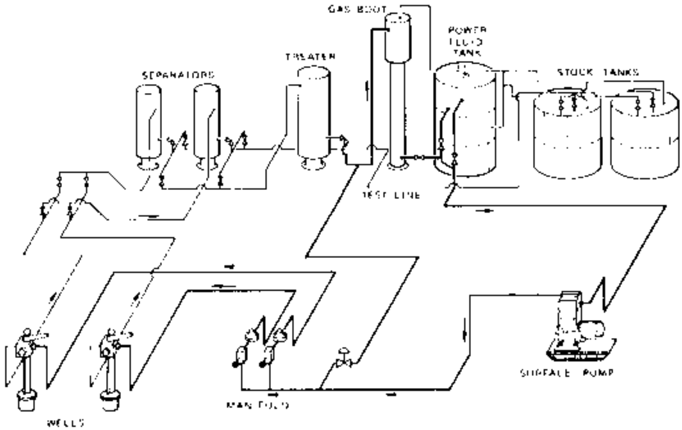

FIGURE 9 Typical central system (Kobe)

FIGURE 10 One-well unitized system (National Supply)

oil or water is then pressurized—typically to between 2500 and 4000 lb/in^2 (172 and 276 bar)—by a power pump at the surface, and then the high-pressure fluid is returned down the power fluid tubing to operate the subsurface hydraulic pump. The exhausted power fluid from the hydraulic pump mixes with the produced fluid from the well, and the mixture is returned to the surface in the parallel side string or the casing tubing annulus.

Figure 9 illustrates a typical central system. The power fluid is separated by settling in tanks. A triplex pump or a battery of triplex pumps manifolded together supplies the power fluid to a number of oil wells. Figure 10 shows a one-well unitized system, in which the combined stream of well production and power fluid is brought into a pressure vessel for a brief period for gas separation and solids settling. The selected fluid is then passed through a cyclone for cleaning before going to the surface pump. The abrasive-laden underflow from the cyclone and the surplus fluid from the pressure vessel then go into the flow line and are carried to the lease tanks. This fluid constitutes the well production.

Subsurface Reciprocating Hydraulic Pumps A subsurface reciprocating hydraulic pump basically consists of an engine piston and cylinder with an engine reversing valve, and a pump barrel and plunger. These are assembled into one unit, and a polished rod connects the engine piston to the pump plunger so the two reciprocate together.

Several designs of subsurface hydraulic reciprocating pumps are available. Figure 11a is a schematic of a double-acting pump. The engine valve directs high-pressure power fluid below the piston and opens the area above the piston to exhaust pressure on the upstroke. On the downstroke, it directs high-pressure power fluid above the piston and exhausts the power fluid below the piston to low pressure. The double-acting design exhausts an equal amount of power fluid from the engine and produces fluid from the pump on the upstroke and downstroke.

Figure 11b illustrates a balanced-design pump where the polished rod area is equal to half of the piston area. The underside of the piston is always connected to high-pressure power fluid. On the downstroke, the engine valve directs high pressure on top of the piston. Because this area is larger than the bottom area of the piston, the unit makes a downstroke. On the upstroke, the engine valve exhausts the area above the piston to low pressure. The high pressure below the piston then causes the unit to make an upstroke. The balanced design exhausts all of the spent power fluid on the upstroke and all of the produced fluid displaced by the pump on the downstroke.

Figure 11c illustrates a single-acting pump where the polished rod area is small relative to the piston area. The underside of the piston is always connected to high-pressure power fluid. The engine valve directs high-pressure power fluid to the top of the piston on the downstroke and exhausts it to low pressure on the upstroke. The single-acting unit exhausts all of the exhaust power fluid and most of the produced fluid displaced by the pump on the upstroke. Only the displacement of the polished rod is exhausted on the downstroke.

In general, subsurface hydraulic reciprocating pumps are used in small- to medium-volume wells. When they are installed in $2\frac{3}{8}$-in (60-mm) OD tubing, they are most commonly used to produce 25 to 500 barrels/day (4 to 80 m^3/day); in $2\frac{7}{8}$-in (73-mm) OD tubing, from 50 to 1000 barrels/day (8 to 158 m^3/day); and in $3\frac{1}{2}$-in (89-mm) OD tubing, from 100 to 1500 barrels/day (16 to 240 m^3/day). Where conditions are right, these volumes can be exceeded, but in the higher volume ranges, the jet pump is usually a better application. Most subsurface hydraulic units have a maximum power fluid pressure rating of 4000 lb/in^2 (278 bar).

Reciprocating hydraulic pumps are available in several pressure ratios. For moderate-depth wells, the engine cylinder and the pump barrel can be of the same diameter. In deeper wells, a pump plunger smaller than the engine cylinder is used; thus the operating pressure can be reduced proportionally, but a proportionally greater quantity of power fluid will be required. Hydraulic pumps are also offered with tandem engines and single pump for deep wells and with single engine and tandem pumps for shallow wells. The pump-to-engine-area ratio in these models varies from a low of 0.40 to a high of 2.00. There is no standardization of design among the various manufacturers, and the models of each are so diverse that no typical charts are offered here. Data can be obtained from the individual manufacturers.

As mentioned previously, the complete up and down cycle of the piston and plunger is called a stroke, and the distance traveled in one direction is called the stroke length. Stroke lengths offered vary from 1 to 5 ft (0.3 to 1.5 m). Stroke-per-minute ratings are from 200 on the shortest stroke to 50 on the longest stroke. The strokes are visible on the surface pressure gage because the pressure rises at each reversal when fluid flow is momentarily interrupted. Because the triplex power pump is positive displacement, the power fluid rate to the pump is usually controlled by bypassing the unneeded surplus. Some triplex pumps are equipped with a three-speed manual transmission that can be used to vary the speed of the surface pump. By selecting the proper rotational speed, the output volume of the surface pump can be adjusted closely to the requirements of the subsurface pump. The triplex pump normally runs continuously, although occasionally in small-volume wells, it will be run intermittently by a time clock.

Subsurface Jet Pumps A jet pump has no moving parts, but it pumps by transferring momentum from a very-high-velocity—1000 ft/s (300m/s)-fluid jet to the pumped fluid

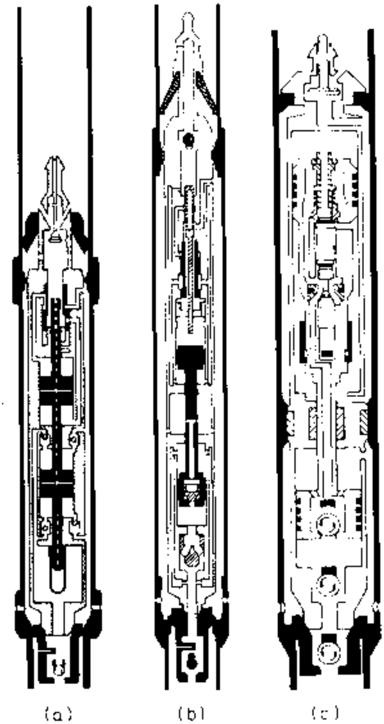

FIGURE 11 Designs of subsurface hydraulic pumps: (a) double-acting, (b) balanced, (c) single-acting

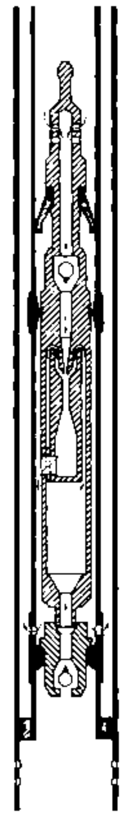

FIGURE 12 Jet free pump

(Figure 12). At the nozzle exit, the jet creates a low-pressure area, thereby drawing in the fluid and carrying it to the throat of the pump, where the momentum transfer is completed. Then the combined stream enters the expanding tapered section of the diffuser, where the velocity head is converted back to a static head. The static head at this point is sufficient to lift the combined stream back to the surface. For a complete description of the general theory of jet pumps, see Chapter 4.

The jet pump has a broad range of application. It has been applied in wells as shallow as 800 ft (240 m) and as deep as 15,000 ft (4800 m). In general, a jet pump is capable of producing wells in the following volume ranges: in $2\frac{3}{8}$-in (60-mm) OD tubing, from 25 to 8000 barrels/day (4 to 475 m^3/day); in $2\frac{7}{8}$-in (73-mm) OD tubing, from 50 to 6000 barrels/day (8 to 950 m^3/day); and in $3\frac{1}{2}$-in (89-mm) OD tubing, from 100 to 12,000 barrels/day (16 to 1900 m^3/day).

Jet pumps are less energy-efficient than reciprocating pumps. A well-designed jet pump may perform at approximately 40% hydraulic efficiency, as compared with more than 90% efficiency for a reciprocating pump. However, jet pumps do have numerous advantages. With no moving parts, they have a high level of reliability, and sustained runs of several years are not uncommon. In addition to their high volume capability, jet pumps have a higher tolerance to abrasives in the produced fluid as well as in the power fluid. They are also more efficient in handling entrained gas in the pumped fluid.

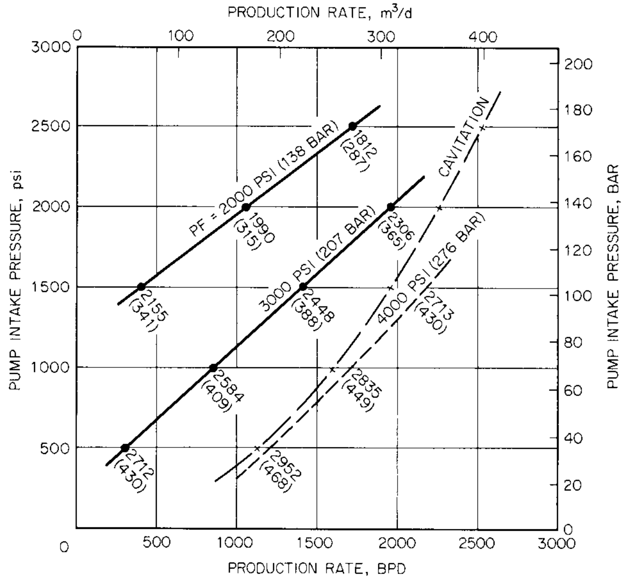

FIGURE 13 Typical characteristic curves for a jet pump. Numbers adjacent to curves are power fluid in barrels (cubic meters) per day. Jet pump operation must be above and to the left of cavitation line.

Manufacturers offer a broad range of nozzle and throat sizes to cover the varied requirements of depths and volumes. Published data show the smallest nozzle requires 13.5 hydraulic hp (10 kW) and the largest requires 506 hydraulic hp (377 kW) at 4000 lb/in^2 (276 bar) power pump pressure. It requires a complex calculation to determine the optimum nozzle and throat sizes for any given set of well conditions. Manufacturers offer computer solutions, usually in graphical form. Variable factors such as tubing friction, changing specific gravity due to gas, and changing well conditions all contribute to the need of a graphical presentation. The chart in Figure 13 shows a jet pump calculation for an 8000-ft (2440-m) well to predict the anticipated production volume versus pump intake pressure for power fluid pressures of 2000, 3000, and 4000 lb/in^2 (138, 207, and 276 bar). Note that at 4000 lb/in^2 (276 bar) power oil pressure, the pump would be cavitating, and this condition must be avoided. Cavitation occurs when the pressure at the entrance of the throat is less than the vapor pressure of the fluid pumped. The collapse of cavitation bubbles in the throat is so damaging that no known metal can resist destruction. Throat life in severe cavitation can be as short as two or three days. It may also be noted from the chart that the jet is very sensitive to pump intake pressure. Both the production rate and the overall hydraulic efficiency increase as pump intake (suction) pressure increases. A down-well pressure-recording instrument may be installed with the jet pump. It records pump intake pressure versus time for a six-day period, at the end of which the jet pump with the instrument is pumped out and the pressure recording read and analyzed. This information is then used to determine if the nozzle and throat sizes are optimum and to select the power fluid pressure that will maximize production but still avoid cavitation.

Subsurface Progressing Cavity Pumps A positive displacement screw-type pump (Section 3.7) can be used for handling the range of oil field fluids. Rotative speed can be varied to match well production with a smooth and steady delivery. No valves are required for pump operation. This type of pump is well suited to handling gaseous formations.

As shown in Figure 14, the rotor is a single rounded-cross-section external screw. The stator is a double internal helix molded of synthetic rubber. As the rotor turns, cavities

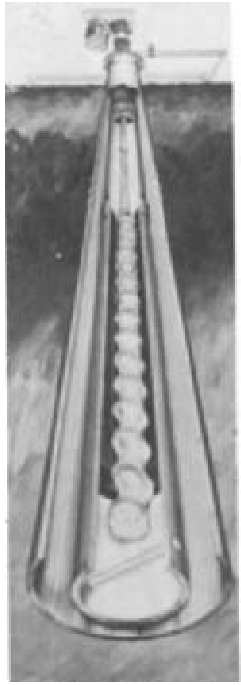

FIGURE 14 Subsurface progressing cavity pump (Fluids Handling Division, Robbins & Myers)

form, and these cavities remain the same size as they progress from the bottom suction to the top discharge. The pump stator is suspended from a standard API tubing string and driven by standard API sucker rod. The pump is electric-motor-driven through belts and sheaves to obtain desired speeds.

Pumps of this type are available for oil well services (or for pumping fluids out of gas wells) to 3000 ft (914) or more. For pumping light or heavy crudes, pump sizes are available up to 100 barrels/day (16 m^3/day) with speeds varying up to 550 rpm and power ratings to 5 hp (3.7 kW), depending on the well depth and flow required. A sucker rod size of $\frac{5}{8}$ in (15.9 mm) is common.

ELECTRIC SUBMERSIBLE CENTRIFUGAL PUMPS

Electric submersible centrifugal pumps are adapted to a wide variety of pumping conditions. However, because of their high capacity, they are most frequently installed in wells where the volume of fluid to be produced exceeds the capacity of sucker rod or reciprocating hydraulic pumps. They are installed suspended from the discharge tubing and submerged in the well fluid. A three-conductor electric cable strapped to the discharge tubing transmits the power to the motor to the end of the pump.

The electric submersible pump system is illustrated schematically in Figure 15. The electric motor and pump rotate at 3500 rpm to 60-Hz power and 2900 rpm for 50-Hz power. The electric motor is directly coupled to the pump with a seal section between the two. The motor is filled with an oil especially selected to provide high dielectric strength, lubrication for the bearings, and good thermal conductivity. The seal section isolates this

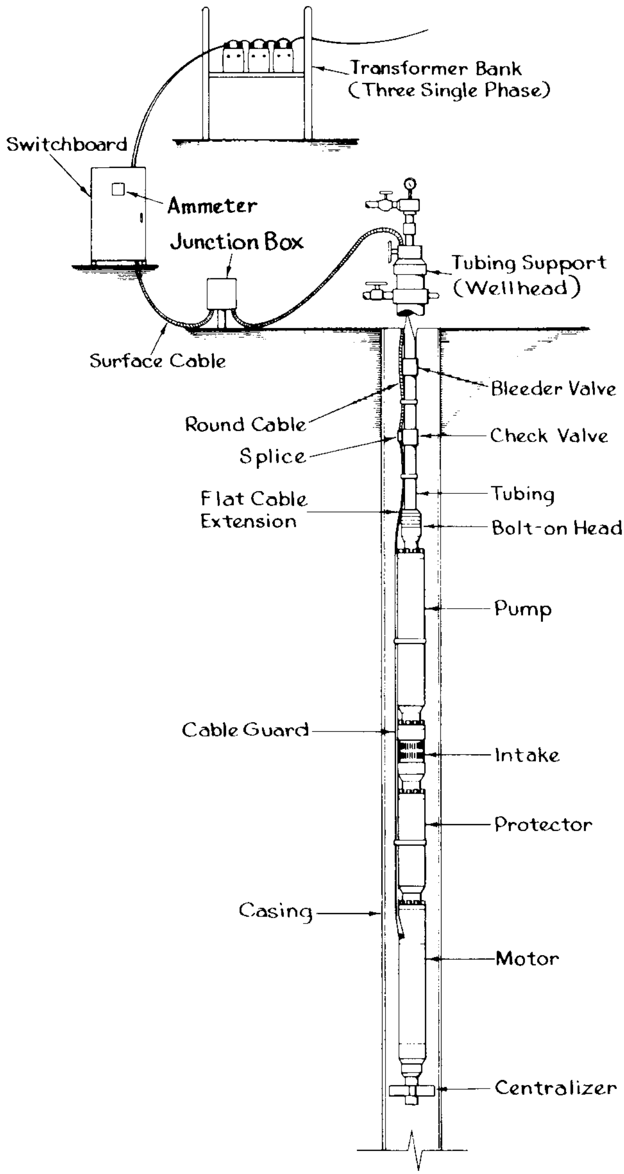

FIGURE 15 Electric submersible centrifugal pump system (PennWell Publishing)

fluid from the pump and allows for expansion and contraction of the fluid with temperature changes at the bottom of the well. The motor, which is the bottom element of the assembly, is usually installed in the well above the casing perforations where the fluid enters the well bore. This allows all of the fluid entering the pump suction to flow past the motor housing and provide the needed cooling.

TABLE 6 Typical characteristics electric submersible centrifugal pumps

Well casing OD, in (mm)	Motor OD, in (mm)	Pump OD, in (mm)	Motor power, hp (kW) Min	Motor power, hp (kW) Max	Pump capacity, bbl/day (m^3/day) Min	Pump capacity, bbl/day (m^3/day) Max	Pump head per stage, ft (m)	Efficiency, pump only, %
4.500	3.75	3.75	25	127	400	1,500	16	54
(114)	(95)	(95)	(18.7)	(94.7)	(64)	(238)	(5.2)	
5.500	4.56	4.56	120	240	400	2,800	23	61
(140)	(116)	(116)	(89.5)	(179)	(64)	(445)	(7.5)	
7.000	4.56	5.40	120	—	1,400	7,000	30	68
(178)	(116)	(137)	(89.5)	—	(223)	(1113)	(9.8)	
—	5.40	5.40	—	600	1,400	7,000	—	—
—	(137)	(137)	—	(488)	(223)	(1113)	—	
8.625	4.56	6.50	120	—	12,000	20,000	42	72
(219)	(116)	(165)	(89.5)	—	(1908)	(3180)	(13.8)	
—	5.40	6.50	—	600	12,000	20,000	—	—
—	(137)	(165)	—	(488)	(1908)	(3180)	—	
—	7.38	6.50	—	720	12,000	20,000	—	—
—	(188)	(165)		(537)	(1908)	(3180)	—	

The small diameter of the casing in which these pumps must be run severely limits design options. Length must be substituted for diameter to achieve the needed characteristics, and the motor design of the electric submersible pump barely resembles its surface counterpart. Single-motor assemblies range up to 32 ft (9.8 m) in length, and when power requirements exceed that of a single motor, two or more motors are assembled in tandem. The pumps must use many stages in order to gain the required head. The smallest-diameter pump—3.75-in (95.2-mm) OD—has 166 stages in an overall length of 12 ft (3.7 m). In deeper wells, two or more of these units can be assembled in tandem to gain the needed head. Manufacturers catalog pump combinations with as many as 400 stages. Table 6 gives typical data on the more common sizes. The numbers in the table are not limits, and manufacturers have available both smaller and larger sizes than those shown.

HYDRAULIC SUBMERSIBLE CENTRIFUGAL PUMPS

Hydraulic turbine drive submersible pumps have been an emerging technology since the 1980s. They are particularly suited for use in wells where other artificial lift technologies are unsuitable due to high liquid viscosity, high temperature, or high gas-to-oil ratio. The hydraulic turbine drive submersible pumpset unit comprises a multistage turbine mounted on a common shaft with a multistage centrifugal pump located directly below it. They are installed in the well bore as part of the production tubing, by wireline or coiled tubing methods, and are submerged in the well fluid.

The simplest hydraulic submersible pump system consists of a surface charge pump, power fluid control valve, hydraulic submersible pumpset, and a power fluid filter (Figure 16). In operation, power fluid is boosted in pressure by the surface charge pump and is passed through the control valve before being injected down the well tubing and into the turbine. The power fluid drives the turbine stages, causing the pump to rotate before exhausting at the lower end of the turbine unit. The pump suction flow enters at the bottom of the pump and is boosted in pressure through the various pump stages before discharging at the upper end of the pump unit. The most common configuration (open loop) results in the discharged pump flow comingling with the exhaust power fluid and returning to the surface for separation and processing. The power fluid is then filtered and

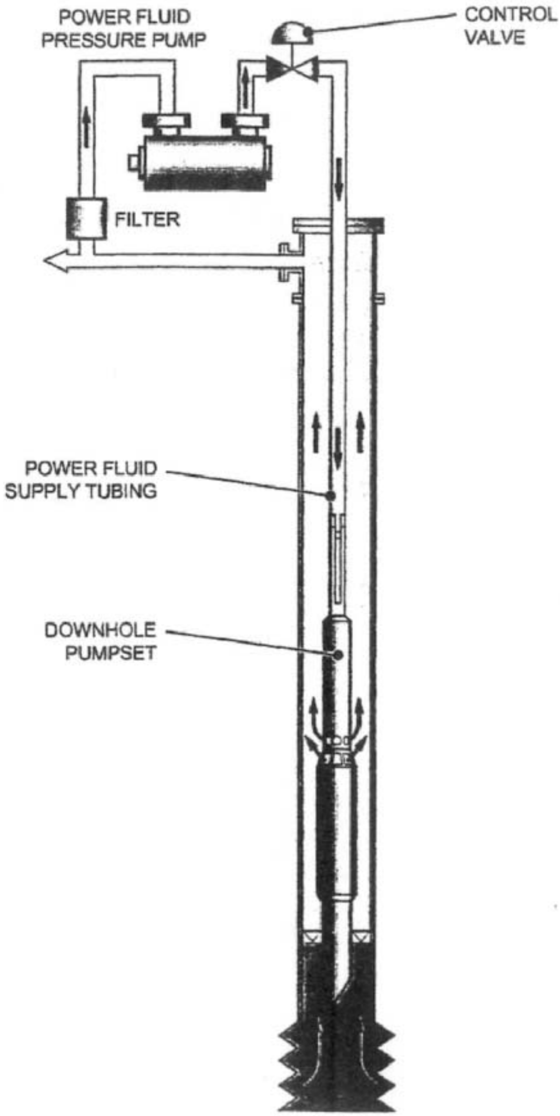

FIGURE 16 Aquifier lift principle of operation (Weir Pumps Ltd.)

returned to the surface charge pump to begin the cycle over again. The turbine power fluid can be produced water, aquifer water, or produced oil, depending on which is more suitable for the application under consideration. The ratio of power to produced fluid is in the region of 1:1, although this can be varied to suit specific operational flow and pressure requirements.

Oil field artificial lift systems require a high degree of flexibility to take account of changing well conditions that may alter over the installed life of the pumpset. The hydraulic submersible pump is a nominally constant power machine that will use all the

TABLE 7 Typical characteristics of a hydraulic submersible centrifugal pump

Well casing OD, in (mm)	Turbine OD, in (mm)	Pump OD, in (mm)	Capacity bbl/day (m^3/day)	Max. Pump Head per stage, ft (m)	Pump Efficiency, pump only, %
5.500 (140)	3.465 (88)	4.528 (115)	8000 (1260)	143 (44)	62
7.000 (178)	5.433 (138)	5.709 (145)	11,000 (1740)	165 (50)	68.5
7.765 (197)	5.433 (138)	5.906 (150)	19,000 (3000)	165 (50)	70
9.625 (244)	6.772 (172)	7.480 (190)	25,000 (3950)	158 (48)	76
10.750 (273)	8.858 (225)	8.662 (220)	39,000 (6160)	158 (48)	78
11.750 (298)	8.858 (225)	10.630 (270)	75,000 (11,900)	193 (59)	79.5

power being fed to it in the form of flow and pressure energy. By this fact, the pump will automatically vary its speed to take into account varying well conditions. Typical pump speeds are in the region of 8500 rpm for smaller unit to 4000 rpm for larger units. Designs are available from 3000 barrels/day to 75,000 barrels/day (480 m^3/day to 12,000 m^3/day), depending on the pumpset configuration. Typical characteristics of hydraulic submersible centrifugal pumps are listed in Table 7.

The hydraulic submersible pump uses clean turbine power fluid to continually flush the pump end bearings while in operation. Hydrostatic bearings are used and the absence of any rolling element bearings or mechanical seals provides a simple, robust construction. The high power density of the hydraulic turbine and the relatively high speed of the pump makes for a compact unit typically less than 20 ft (6 m) long.

OFFSHORE OIL WELL PUMPS

Most offshore oil well platforms are located in high-pressure fields where the wells will flow from natural pressure for several years. When the pressure declines, the wells are frequently produced with gas lift, where high-pressure gas is directed down the casing. This gas mixes with the well fluid at the bottom of the tubing, and the fluid-gas mixture lightens the fluid gradient in the tubing string to a point where the bottom hole pressure is sufficient to cause the well to flow. Where gas lift is not applicable, wells are pumped with subsurface submersible electric pumps, subsurface hydraulic reciprocating or jet pumps, or sucker rod pumping systems. A few wells are completed with the well head on the ocean floor. These must either flow or be gas-lifted, and the other systems are not applicable.

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