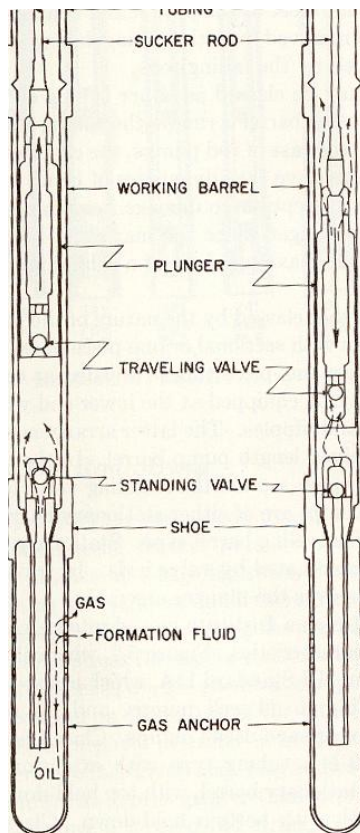


SECTION 3 ARTIFICIAL LIFT

Sucker Rod Pumps

Mechanically simple this is the most common of the pumping systems. The system basically consists of a downhole standing valve and a traveling valve that is moved by a string of sucker rods that connect it to the surface equipment.

The pumping cycle starts with the lifting of the traveling valve (TV) at the bottom of the stroke, the TV is closed and the standing valve (SV) is opened. This lifts the fluid above the TV and allows fluid to enter the pump through the SV. At the top of the stroke when the TV starts down and is opened and the SV is closed. The fluid that is now in the pump is trapped there by the closing of the S V and TV moves under the fluid by being open. The TV and SV are ball and seat type valves that are in cages to restrict the movement of the ball.



There are 4 major components in a sucker rod pumping system,

- 1) Prime mover, the energy source of the system (motor or engine)
- 2) The surface pumping equipment, moves the rods (pump jack)
- 3) The sucker rods, connection of the surface to downhole
- 4) The downhole pump

The system is a complex interconnection of all these parts and each has to be designed with the others in mind for a total desired result.

The Pump

There are two types of rod pumps, tubing pump and the rod or insert pump.

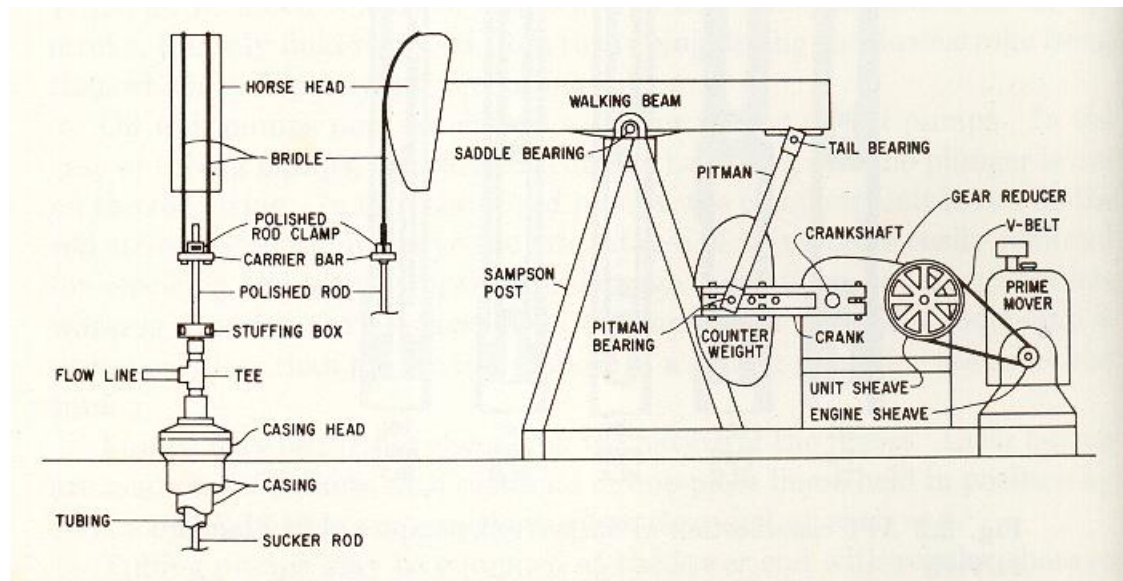
- 1) Tubing Pump, the barrel of this type of pump is part of the tubing string. The plunger (traveling valve) is run on the end on the rods, the standing valve is dropped before running the rods and plunger and can fished out without removing the barrel of the pump. This system allows for larger pump barrels and plunger thus the ability to move large volume of fluids, the downside is if the barrel needs to be repaired the entire tubing string has to be pulled from the well.
- 2) Rod or Insert Pump, the entire assembly of this system is run on the rods, and inserted into a seating nipple in the tubing. The advantage here is the ease of maintenance; it is easier to pull the rods to recover the pump for repair than the tubing string. Downside is the pumps are smaller, they have to fit inside the tubing, smaller volumes are be pumped.

Rods

The rods that connect the pump to the surface are basically steel but in some high corrosion environments fiberglass rods are used. The steel rods come in various grades depending on the strength and corrosion resistance needed. The rods are the weakest part of the system, and is the main focus of maintenance required for this pumping system. Design of the rod string is critical to the overall performance and economics of the well. Rod strings have single or tapered diameters depending on the depth of the well and the amount of fluid needed to be pumped. The rod consists of two components, the rod body and the box which connects the individual rods. The pins of the rod, the threaded ends, are also an area of weakness in the system.

The care of the rods during shipping, storage and, running is very important as they are easily damaged. The amount of torque when making up the rods is also very important in the longevity of the rod string.

At the top of the rod string is a polish rod, this is a smooth rod that goes through the stuffing box, the packoff on the tubing, and is clamped so it can be hung in the bridle of the pump jack.



The Pump Jack (Surface Equipment)

The major components of the pump jack to be considered in design of the pumping systems are, 1) the gear box, 2) Polish rod load, 3) length of stroke, and 4) the maximum allowed counterbalance. The API designation of pump jacks is a series of 3 numbers, inch pounds of torque on the gear box in thousands, polish rod load in hundreds of pounds, and the stroke in inches. So a jack with the model number of

456 -650 -144 API

will have 456,000 inch pounds of torque, a maximum prl of 65,000 pounds, with a maximum stroke of 12 feet. Each manufacturer will also have some company designations in the model number for the design of the jack.

The main function of the jack is to convert the rotary motion of the prime mover to an up and down motion so the rods can move the TV up and down in the well. There some different designs to do this without the shock in the

change of direction and to help with the counterbalancing of the jack. The air-balance unit and Lufkins Mark series are examples of this.

Once the Jack is sized properly it is important to have the counter balance weights set right, this will increase the life of the gear box and lower the required horsepower needed to pump the well.

The Prime Mover

Is the engine or electric motor that runs the system. Electric motors give a flexibility for the timing of pumping cycles. They also have a lower maintenance costs than gas engines. Not all wells are near a power grid and start costs of bring in a line can be high. Gas engines can be cheaper to operate since they can run on gas from the well.

Design Considerations

The pump, after deciding how much volume needs to be pumped, the length and the diameter of the plunger of the pump is calculated with the speed of the pump jack in strokes per minute. The length of the pump must be long enough to allow for the "overtravel" of the plunger, this is caused by the stretch of the rods as they change direction. The length of the stroke is limited by the pump jack, smaller jacks have smaller strokes. After the pump is sized the rod string is designed that can handle the stresses of the fluid and its own weight along with the weight of the fluid. This is restricted by the size of the tubing in the well as is the barrel size of the pump. A pump jack that meets all the design criteria is found and the horsepower required is calculated along with the counterweight that will be needed for an efficient pumping system.

Other Down hole equipment

Tubing Anchor

The loading and unloading of the standing valve causes the tubing to stretch and contract in the well. This motion has to be accounted for in design the length of the pump stroke. This can be very large in deep wells and wells that are pumping a large volumes of fluid. A tubing anchor eliminates this problem by anchoring the tubing to the casing usually just above the pump. The tubing is set in tension to keep the rods from rubbing on the tubing if possible.

Gas Anchor

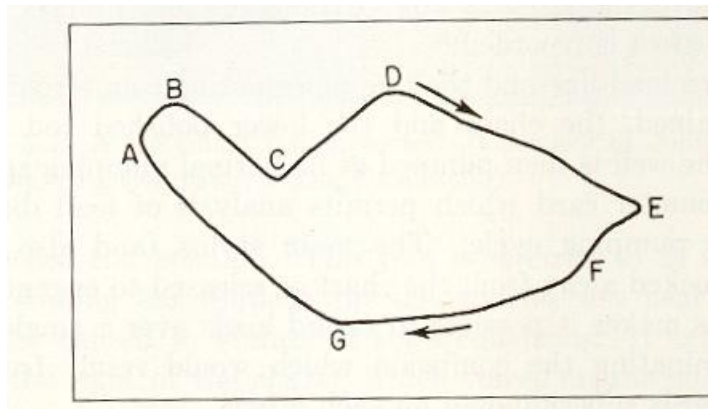
This is a tube with holes in the bottom portion that screws in the pump intake and helps knock out the gas before the well fluid enters the pump. This is accomplished by forcing the fluid to move down the tubing from the perforated sub before going into the pump.

Mud Anchor

A blanked off joint of tubing below the perforated sub, used to help keep fines from entering the pump.

Dynamometer Cards

Used to diagnose problems in the sucker rod pumping system. The card is a continuous plot of the polish rod load vs. its displacement. Point A in the figure is the start of the upstroke, E is the start of the downstroke.



Analysis of these card can be complicated because many of the variables that affect the loading. They sometime nullify each other and other times are additive and sometime time shift the effects.

Electric Submersible Pumps

The production rate range for ESP is 100 bfpd to 90,000 bfpd, but is used mostly for large production rates. Most systems produce under a 1000 bpd of fluid. It is very good when large amounts of water is produced with the oil. It is used in many water wells today. ESPs are not good for wells with a large gas cut. This is a very expensive system in install and to maintain.

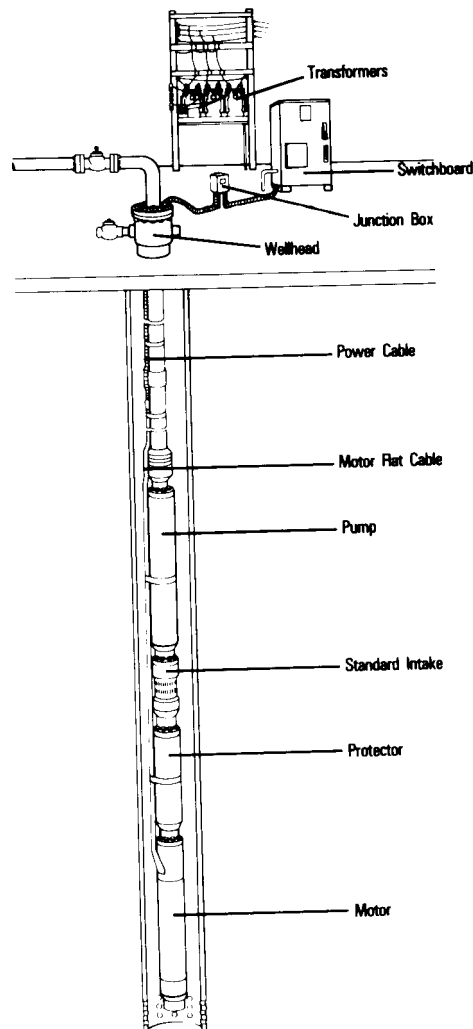


Fig. 7.1—Typical submersible pump application.

ESP Components

Motor – The prime mover of the system is an electric motor that is a two – pole, three phase, squirrel cage induction motor that runs at 3500 rpm at 60-Hz. The formation fluid moving by the motor housing cools these motors. So the flow must be adequate and the pump must not be set below the perforations. The motors come in four different diameters, 3.75, 4.56, 5.4 and 7.38 inches. Several motors many arranged in tandem configurations to supply the required horsepower to pump the desired flow rate.

Pump – A multistage centrifugal type pump is used for ESP systems. The impellers used are bronze or plastic for corrosion protection. They have a “bolt on” design so that several pump stages are used to get the capacity and the head needed for the well.

Protector – Primary purpose to isolate the motor oil from the well fluid while balancing BHP and the motor internal pressure. The other functions are 1) connecting the pump to the motor, 2) house the thrust bearing to absorb pump shaft axial thrust and 3) allows thermal expansion of the motor oil.

Power Cable – To supply the electric power to the motor downhole. Two configurations of power cables, flat (parallel), and round are used. Mechanical protection is given by armor of galvanized steel.

Switchboard – Is the surface control of the system. It basically a motor control panel for outdoor use. It also has a recording amp meter that is used to monitor the operation of the pump and motor.

Wellhead – A special type of wellhead is used, to pack off the tubing and the power cable.

Selection Data

Mechanical Data

- 1) Casing and tubing size
- 2) Well depth, measured and true vertical
- 3) Perforations depth, measured and true vertical

Production Data

- 1) Oil production rate
- 2) Water production rate
- 3) GOR
- 4) Static BHP and fluid level
- 5) Producing BHP and fluid level
- 6) BHT
- 7) System backpressure

Fluid Data

- 1) oil viscosity, paraffin and sand content
- 2) water gravity, chemical content
- 3) gas gravity
- 4) FVF

Power Supply

- 1) Voltage available
- 2) Capacity of the system
- 3) Quality of the system

Gas Lift Systems

Gas is injected continuously or intermittently at selected locations, resulting in the lifting of the produced fluids to the surface. This is accomplished by lowering the hydrostatic load in the tubing by the addition of the gas. The lowering of the bottom hole pressure is also accomplished.

The lifting of well fluids is accomplished by one of two methods:

- 1) Continuous – Continuously injecting gas into the tubing or casing at a predetermined depth to reduce the pressure opposite the producing formation.
- 2) Intermittent Flow – Injection of high pressure gas into the tubing at sufficient volume and pressure to lift the fluid head accumulated above the valve with maximum velocity. (De-watering gas wells)

Advantages of Gas Lift

- 1) Low initial and operating costs
- 2) Flexibility of production, can produce at high and low rates
- 3) Effectively produce high GOR and WOR wells
- 4) Deep wells, deviated wells
- 5) Subsurface equipment can use wireline workover techniques
- 6) Dual completed wells

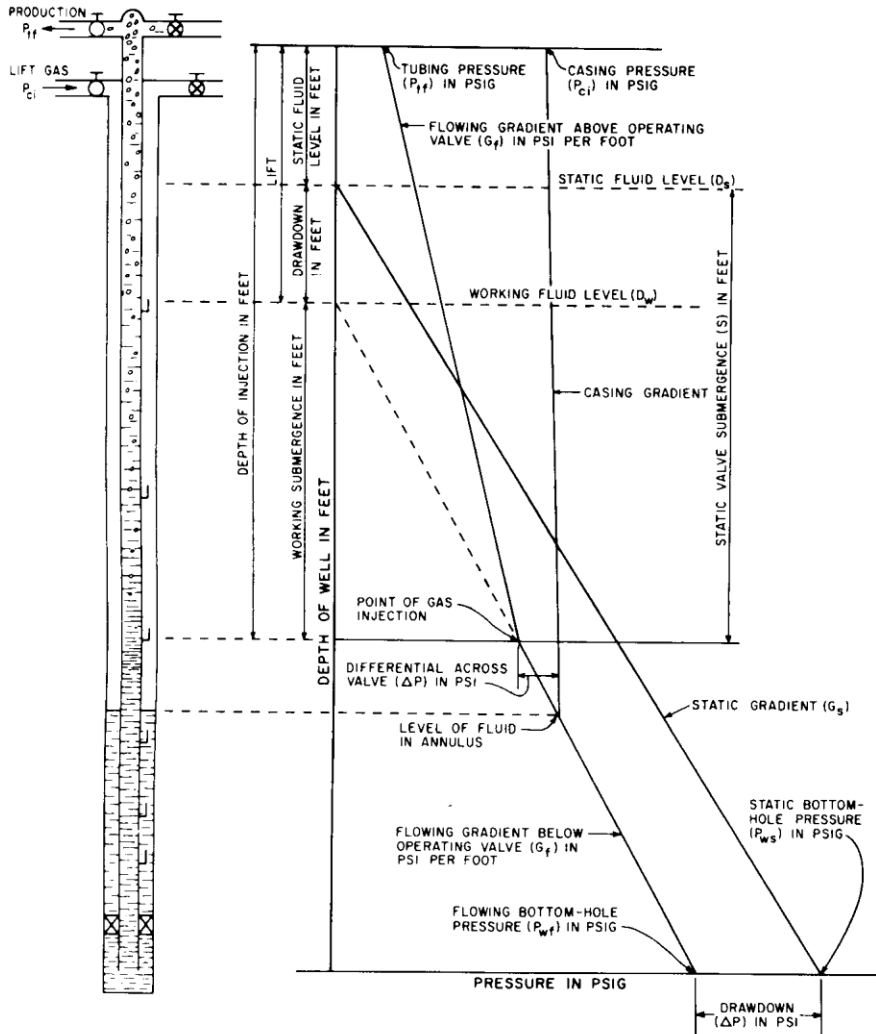
Factors that limited effectiveness of gas lift

- 1) Sour gas
- 2) Wet gas subject to freezing
- 3) Paraffin
- 4) Low viscosity crudes

The four well categories considered for gas lift

- | | |
|-----------------------|--------------|
| 1) High PI – High BHP | continuous |
| 2) High PI – Low BHP | intermittent |
| 3) Low PI – High BHP | continuous |
| 4) Low PI – Low BHP | intermittent |

Note; here High BHP is a BHP that can support the liquid for 70% of depth, low is less than 40% of depth.
 Low PI is less than .5 BOPD/psi.



Continuous Gas Lift System

Design Factors

- 1) Gas injection depth, pressure and GLR for desired production
- 2) Principles of unloading operations
- 3) Well gradients
- 4) Gas lift valve spacing principles

- 5) Types of gas lift valves
- 6) Mechanics of gas lift valve operation
- 7) Factors that affect efficiency

Determination of gas injection depth and pressure along with the GLR can be obtained using the PI of the well.

Unloading is the process by which the valves in the casing are uncovered, the fluid is pushed below the valve, and the effects in the tubing as this happens.

There are two distinct gradients used here, one for the valve spacing and one for ultimate gas lift production design. The gradient across from a valve just before it opens is made up of the tubing head pressure, aerated flowing gradient above the valve and the Non-aerated flowing gradient up to the valve above it. These gradients change, as more valves become uncovered down to the kick off valve.

Valve Spacing Principles require knowledge of 1) Well unloading characteristics; 2) well gradients, and 3) types of valves and the mechanics of their operation.

Types of Gas Lift Valves

- I) Type of service
 - A. Continuous flow
 1. Fixed orifice
 2. Variable orifice
 - B. Intermittent flow
 1. With minimum tubing pressure control
 2. With maximum tubing pressure control

- II) Type of loading
 - A. Gas charged bellows chamber
 - B. Gas charged piston chamber
 - C. Gas charged rubber diaphragm chamber
 - D. Spring
 - E. Spring, pilot loaded
 - F. Combination spring and gas charged bellow
 - G. Liquid charged diaphragm chamber

H. No loading pressure- mechanical operation

To understand the mechanics of the valves, the operating pressure of the valves must be known. This pressure is set by different methods depending on the type of the valve used. The pressure to open a valve is equal to 1) Pressure necessary to overcome the pressure charge inside the bellows, 2) Full pressure effect of the spring and 3) Minus the effective tubing pressure helping to the valve.

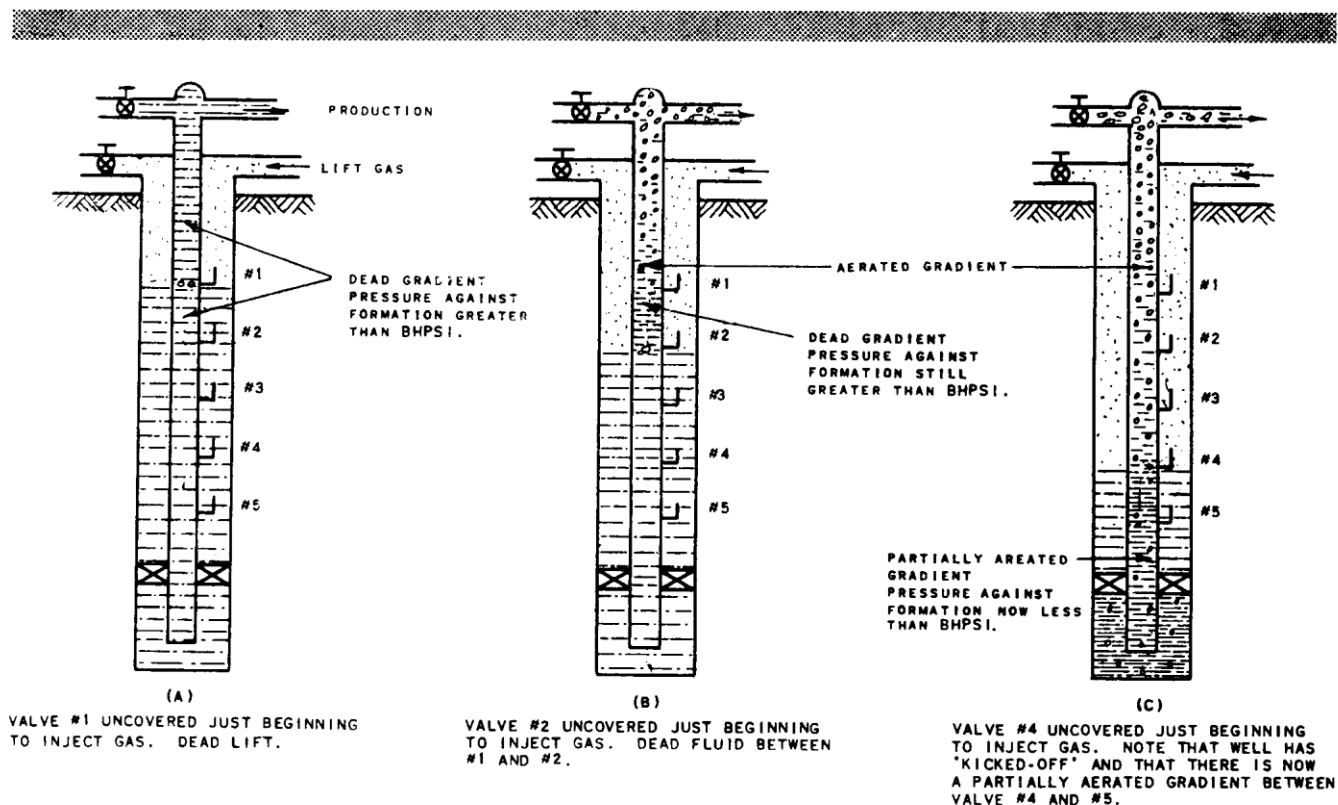


FIG. 2. Steps in well unloading firmly demand correct valve spacing. Spacing is determined by various fluid gradients.

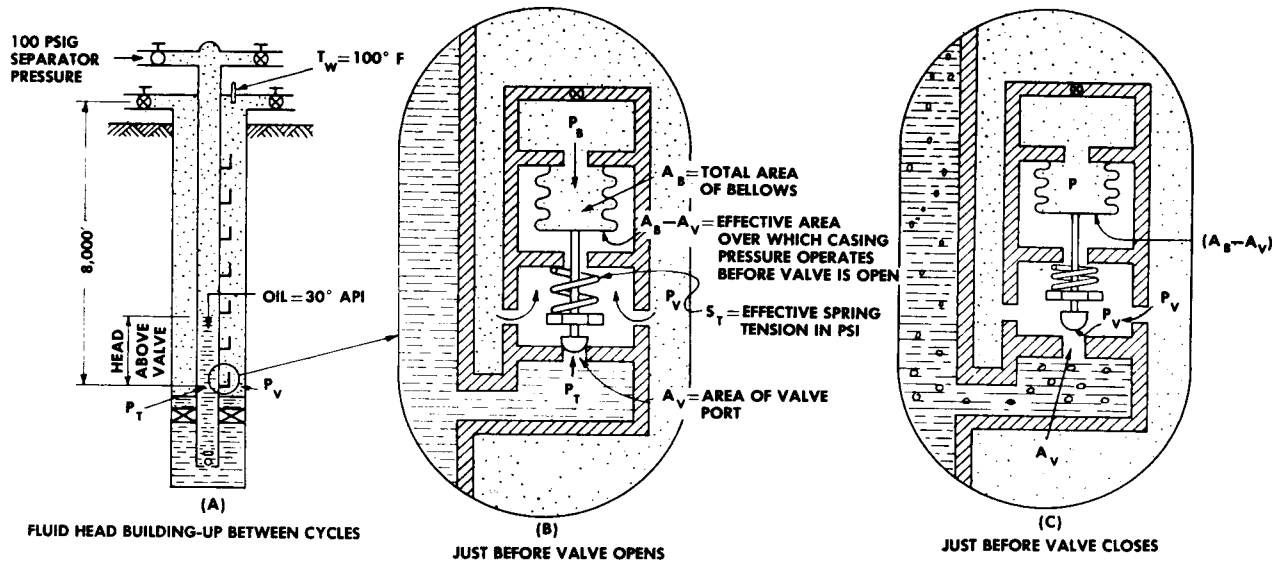


FIG. 8. Schematic diagram of valve operation used in calculating valve spread.

Intermittent Flow Gas Lift Wells

Types of Intermittent Installations

- 1) Conventional type
- 2) Gas Lift Plunger with outside gas source
- 3) Gas Lift Plunger without an outside gas source; use the gas from the well.

The Design Considerations

- 1) Kick off pressure
- 2) Continuous operating gas pressure
- 3) High or low fluid level
- 4) High or low PI
- 5) BHP build up rate
- 6) Available gas and the theoretical minimum requirement
- 7) Production desired
- 8) Valve setting and spacing for unloading and operating

These systems are used to remove slugs of fluid from the well. Very common in gas wells that makes a lot of water. The rate that the well builds up pressure is a major factor in the timing of the production cycles for the well.

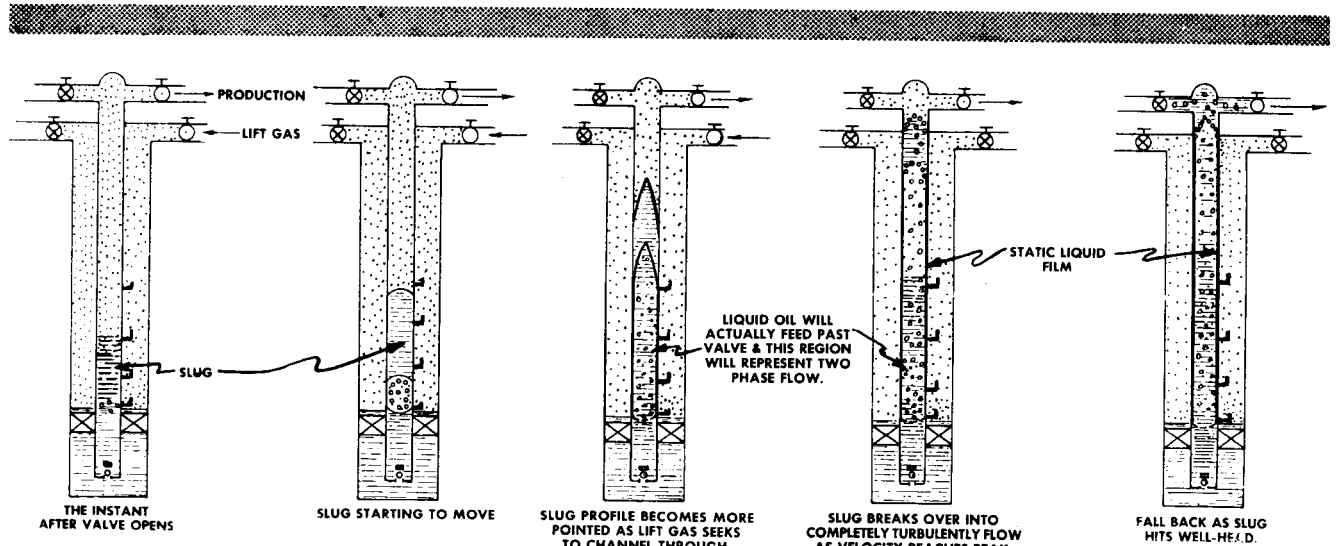


FIG. 9. Progressive stages in intermittent flow. Producing rate is dependent upon fill-in and pressure of fluid column in tubing between slugs.

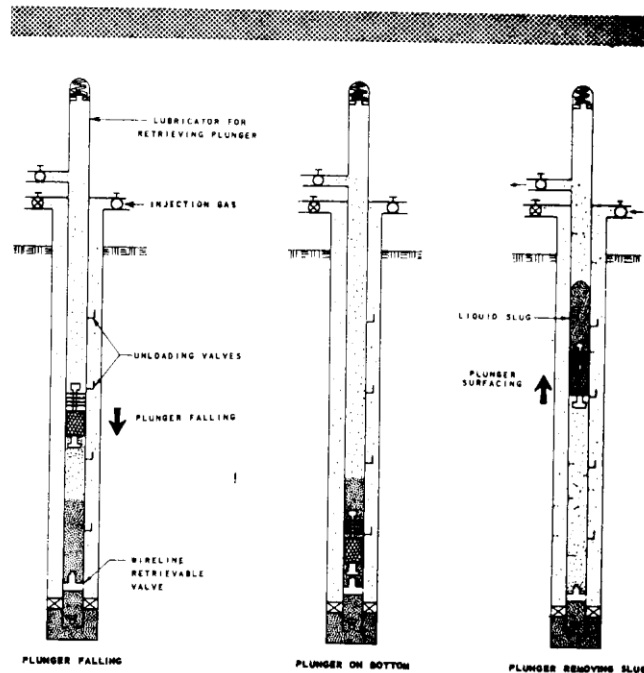
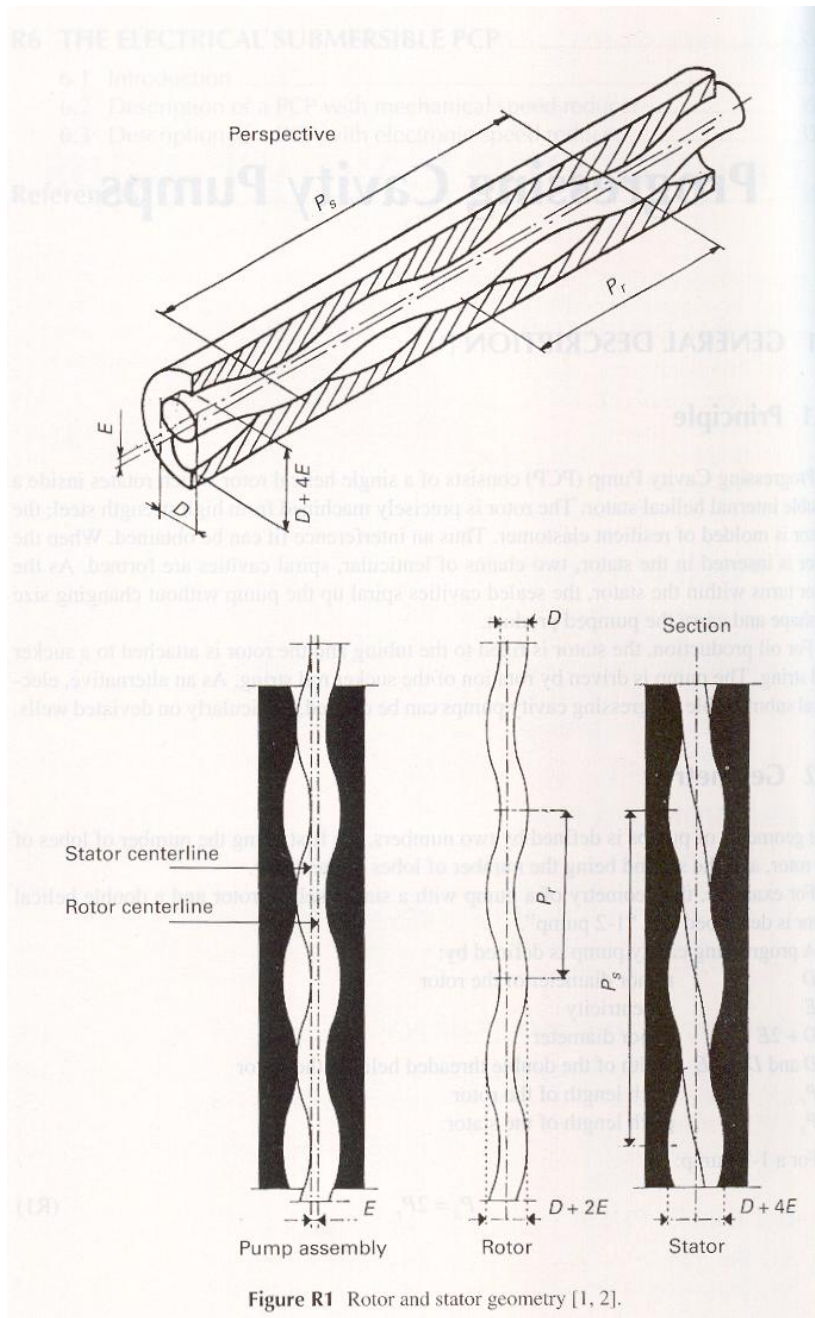


FIG. 13. Plunger lift with retrievable gas lift valve. Plunger reduces slippage per cycle encountered in conventional systems.

Progressing Cavity Pumps

A PCP consists of a single helical rotor which rotates inside a double internal helical stator. When the rotor is inserted in the stator, two chains of lenticular, spiral cavities are formed. As the rotor is turned, the sealed cavities spiral up the pump without changing size or shape and carry the fluid.



Since the rod string with a PCP is rotated, these systems can be run in deviated holes. Low viscosities and high GLR wells can be pumped using this pumping system.

The PCP is a simple pump whose performance and operating time depend on some basic parameters.

Elastomer behavior: The material the stator is composed of.

- 1) Frictional wear (abrasives present in fluid.
- 2) Gaseous hydrocarbons which may diffuse into the material and alter mechanical properties.
- 3) Operating temperature.

Rotating speed limited by:

- 1) The rotor imbalance which is equal to $M\omega^2$
- 2) The friction speed of the rotor in the stator.

Design factors

Pump displacement is the volume of fluid produced in one revolution of the rotor.

$$V_o = 4E \times D \times P_s$$

Calculated flow rate

$$Q_c = V_o \times N$$

Actual flow rate

$$Q_a = Q_c - Q_s$$

where Q_s is the leak rate.

Head rating.

Determined by the cavities formed between the rotor and stator

Mechanical resistant torque

$$\Gamma_m = 1.63E - 5 \frac{V \times \Delta P}{\rho}$$

Load on the thrust bearings or the load on the drive string.

Operational Conditions

Pumps are chosen based on the following

- 1) The flow rate and the head rating
- 2) The diameter and the depth of the equipment
- 3) The drive system

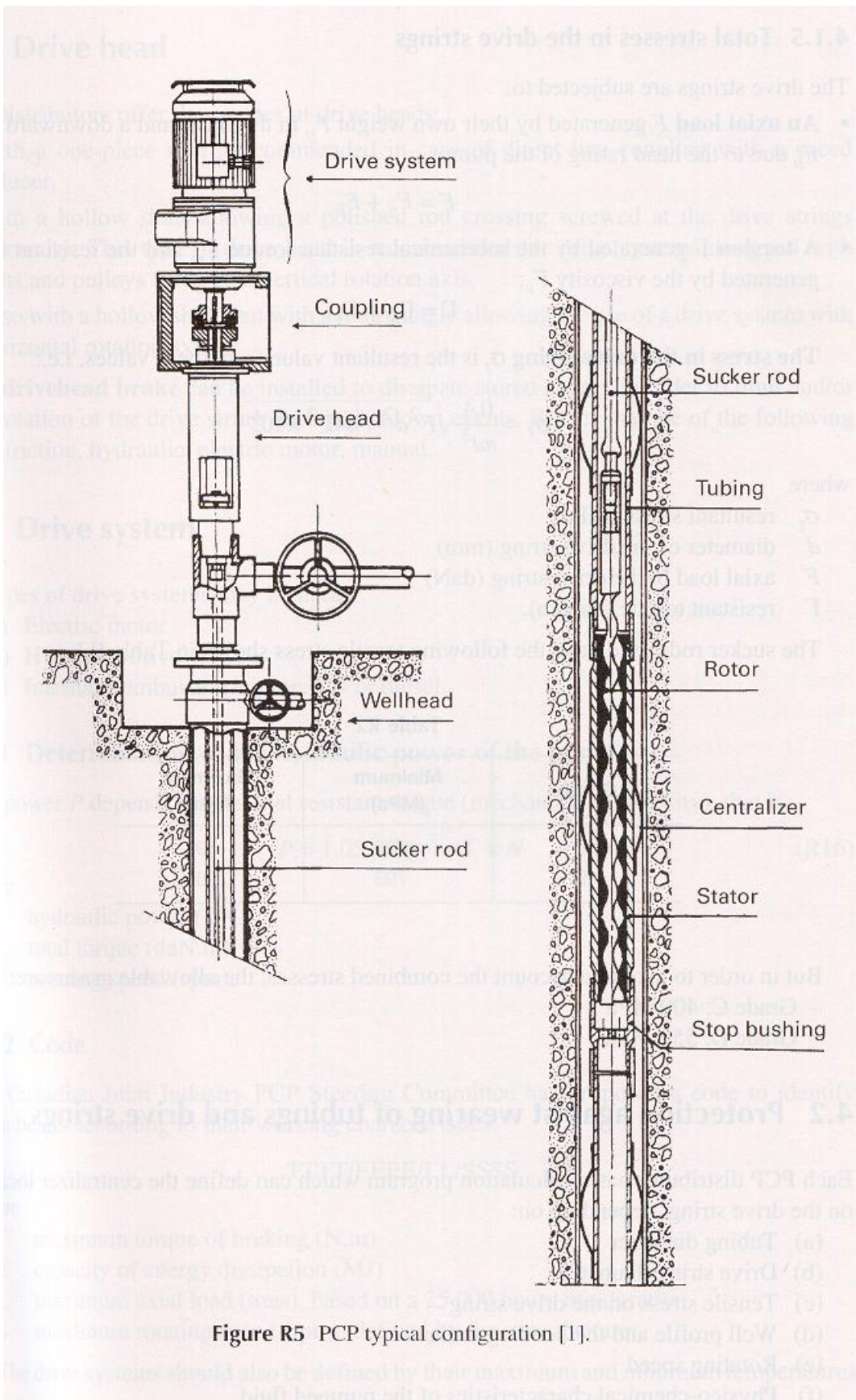


Figure R5 PCP typical configuration [1].

