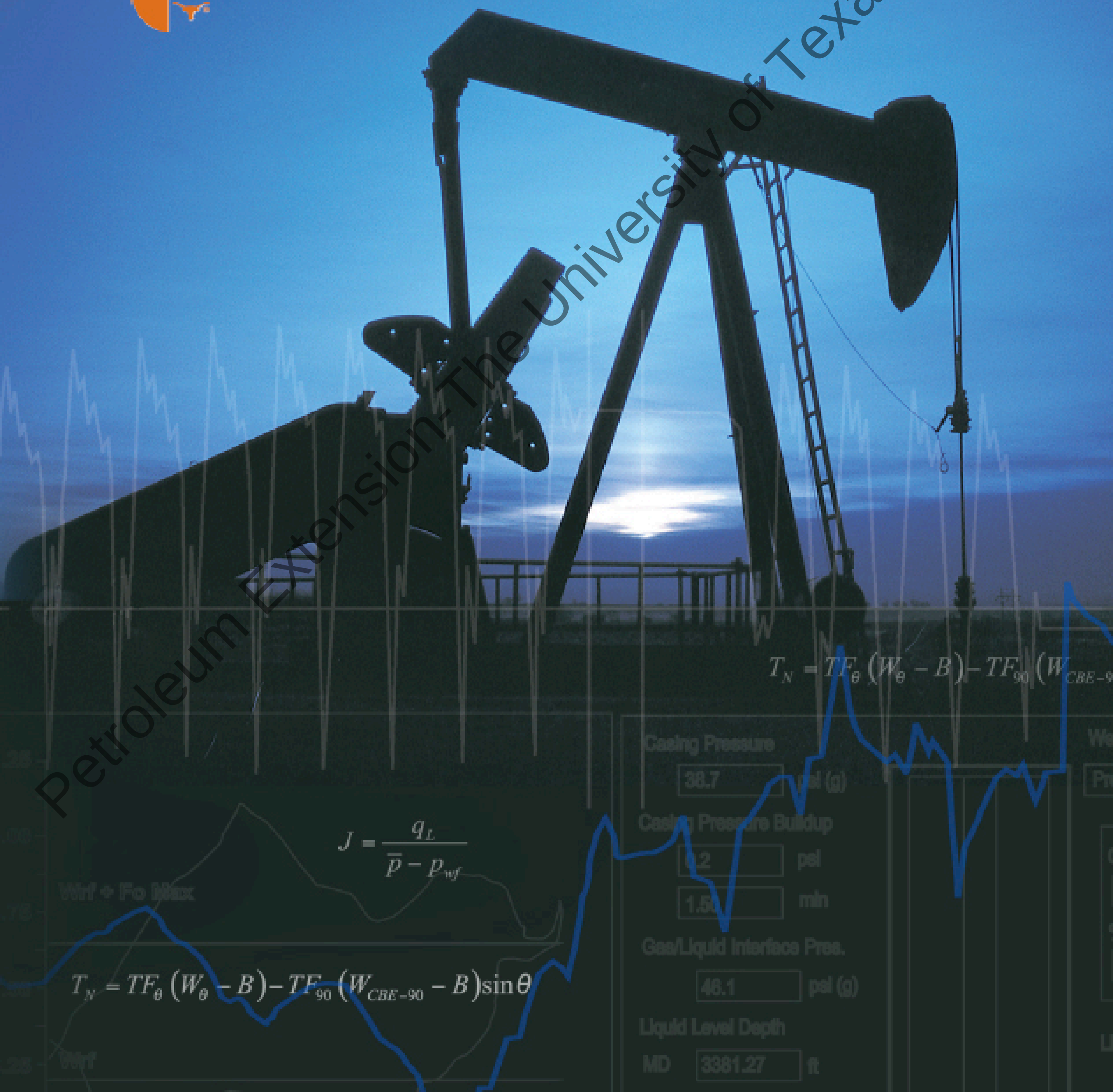
The Beam Lift Handbook

First Edition, Revised

Paul M. Bommer and A. L. Podio

The University of Texas at Austin
PETROLEUM EXTENSION



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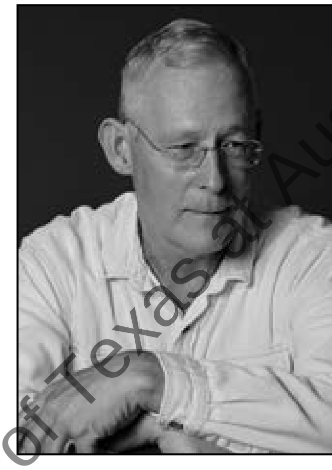
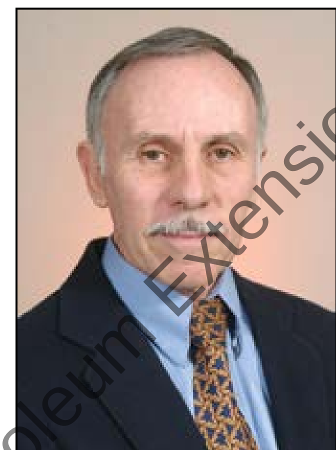
About the Authors



Paul M. Bommer is a Senior Lecturer in Petroleum Engineering at The University of Texas at Austin. He received his Bachelor's (1976), Master's (1977), and Doctoral (1979) degrees in petroleum engineering, all from The University of Texas at Austin.

He spent over twenty-five years in industry as an oil and gas operator and consultant in Texas and in other parts of the United States. He and his brother Peter (The University of Texas, BS-PGE, 1978) are co-owners of Bommer Engineering Company.

He is a third generation oil man following both his father (The University of Texas, BS-PGE, 1950), who was a highly regarded petroleum engineer in Texas as the principal owner of Viking Drilling Company in San Antonio, and his paternal grandfather, who was a field superintendent in Oklahoma, East Texas, and on the Texas Gulf Coast for Stanolind Oil Company (later Amoco). As with many of her generation of oilfield families, his mother (The University of Texas, BS-HEc, 1949) made sandwiches for the crews and curtains for the tool pusher's trailer, created a home, and raised the kids.



A. L. Podio is currently a Research Professor in the Petroleum and Geosystems Engineering Department at the University of Texas at Austin where he has taught and directed research in the areas of drilling and production since 1971. He holds a Bachelor of Science degree in Mining and Petroleum Engineering from the University of the Andes in Bogota, Colombia, and a Bachelor of Science, Master of Science, and PhD in Petroleum Engineering from the University of Texas at Austin. He is a registered Professional Engineer in Texas, has been a distinguished speaker and technical editor for the Society of Petroleum Engineers, has published numerous articles international journals, and holds seven U.S. patents.

1

Beam Lift Goals And System Design

GOALS

It is important to state the goals of beam lift and then design the equipment to meet the goals. It is perhaps even more important not to forget the goals of beam lift when well conditions change.

The first goal of beam lift is stated as follows:

1. The primary goal of beam lift, indeed of any artificial lift device, is to produce all of the liquid that a reservoir can flow into the bottom of the well on a continuous basis, as long as no harm is done to the reservoir or the well equipment.

This goal is based on the underlying assumption that the value of the well is directly proportional to the ultimate hydrocarbon recovery from the well. The maximum ultimate recovery from the well will be achieved if the first goal is met.

The reservoir has a maximum *flow rate* that can be sustained by the current pressure in the reservoir. Equation 1.1, which shows the simple relation of the *productivity index* (J), demonstrates this.

$$J = \frac{q}{\bar{p} - p_{wf}} \qquad \text{Eq. 1.1}$$

J = productivity index $\left(\frac{\text{stock tank barrels [STB]/day}}{\text{psi}}\right)$

q = liquid flow rate $\left(\frac{\text{STB}}{\text{day}}\right)$

$\bar{p}$ = average reservoir pressure (psi)

p_{wf} = flowing pressure inside the wellbore at the perforations (psi)

Productivity index is an elegant and powerful tool that can be used to describe the flow capabilities of a reservoir at a particular time. It includes implicitly all of the influences of the reservoir and the completion outside of the wellbore. The data required to establish the productivity index are readily available from well tests. The productivity index concept is applicable to a reservoir that is producing liquids that are largely gas free. This is the case for wells that are producing from reservoirs where the pressure is above the *bubble point* or for reservoir fluids that do not contain significant gas in solution.

If the pressure in the reservoir is below the bubble point and if a significant volume of *free gas* flows from the reservoir, a better inflow performance model is either Vogel's Equation or Fetkovich's Approximation[1]. Vogel's Equation is shown as equation 1.2.

$$q = q_{\max}\left[1 - 0.2\,\frac{p_{wf}}{\bar{p}} - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2\right] \qquad \text{Eq. 1.2}$$

$q_{\max}$ = maximum liquid rate $\left(\frac{\text{STB}}{\text{day}}\right)$ at $p_{wf} = 0$ psi.

2

Monitoring and Analysis of Performance

Correct diagnosis of trouble and inefficiencies in a pumping well can result in increased production and/or savings in operational and remedial costs. The general objective is to have maximum production for each investment, operation, and repair dollar.

Before any form of maintenance or repairs is undertaken, the specific trouble or the reason a pumping well is not producing the expected volume of fluid should be determined; *dynamometers* and *fluid level* instruments are the principal tools used for this purpose. As such, it is desirable to maintain accurate and timely records of well production rate, the *water–oil ratio*, and the *gas–oil ratio* in order to identify easily those wells that require attention and further study. Unfortunately, the relatively common practice of commingling flow from different wells on a lease or in an area into a common surface processing facility, with no ability to isolate individual streams, makes identification of the troubled well more difficult and inefficient. When the tank *gauge* displays a 24-hour volume increase that is lower than expected, it becomes necessary to identify the well or wells not operating normally. This procedure involves first identifying surface units that might be inoperable due either to a lack of power or to other mechanical problems or identifying either unusual visible or audible operational characteristics or other unusual features, as discussed in chapter 3. Having identified the likely well or wells not performing as expected, the next step is to perform various measurements at the surface, including fluid level and dynamometer records.

RECOMMENDED PRACTICES FOR THE MONITORING AND ANALYSIS OF PUMPING SYSTEM PERFORMANCE

- Monitoring and testing actual production of the well on a regular schedule is fundamental to keeping artificial lift systems operating at peak performance and efficiency. Details and guidelines are discussed in chapter 5.
- Basic routine measurements at the surface (for example, dynamometer, fluid level, and power measurements) are used for monitoring the operation of the rod pumping system in real time. Details are discussed in chapter 11.
- Diagnostic analysis of the surface measurements are used to troubleshoot problems detected. Guidelines are discussed in chapter 3.

Dynamometer Analysis

The best way to monitor the performance of a pump and pumping equipment is using dynamometer analysis. This is the most accurate method because the data used are the actual loads carried by the rods at the surface, as a response to the performance of the pump, in relation to the productivity of the formation and *wellbore pressure*. For this reason, correct analysis of the dynamometer record also requires accurate knowledge of the corresponding distribution of fluids and pressure in the well. Details of fluid level measurements and analysis are discussed in chapter 11.

The dynamometer, which is described in greater detail in chapter 11, is a device that records the weight carried by the polished rod during a stroke. The load at the polished rod is the reaction to the forced motion of the pump plunger transmitted from the surface via the rod string.

3

Troubleshooting and Analysis Guidelines

"*Walking beam activated sucker rod pumps are the most idiot proof artificial lift method devised by man to date.*" Fred Gipson, 1989 Southwestern Petroleum Short Course[1]

The nature of rod pumping has an inherently forgiving aspect. For this reason, rod pumping requires special effort in order to visualize the true performance of a pumping unit that appears to be operating normally. This effort is undertaken in order to identify potential problems and operating conditions that can result in failures or that can prevent the objective of producing all the fluid being delivered to the well by the reservoir in the most efficient and cost-effective manner from being achieved. The purpose of this chapter is to outline methods and procedures that facilitate the evaluation of the current performance of a pumping system so that appropriate remedies may be applied as necessary.

Various surveys of operators and service companies[2] have indicated that the most common problems related to rod pumping include the following (in order of decreasing frequency):

- An inability to maintain a high volumetric efficiency
- Difficulty in handling gas in the pump
- Sand and solids in the pump
- Excessive rod and tubing wear
- Corrosion

The presence of the first four problems listed above can be identified using detailed analysis of fluid level and dynamometer records, from which the conditions in the wellbore and the pump can be correctly visualized. The final problem listed—corrosion—is addressed in chapter 7, and prevention of this problem involves the proper selection of materials and the addition of chemicals to retard corrosion rates.

In order to successfully analyze and identify the root causes of the problems mentioned above, accurate data is a necessity. The first step in acquiring accurate data is to create a detailed wellbore diagram that describes the mechanical completion and the hardware installed in the well. The next step is to complete this diagram with the current distribution of fluids and pressures in the wellbore, the performance of the pump, and the loads supported by the rods and surface unit. Usually, the software application that is used to analyze the dynamometer and fluid level data will include the necessary tools to generate the needed reports; otherwise, there are various software packages that can help in constructing and managing well data.

Ideally, the following information should be compiled and checked for accuracy:

- Wellbore description
- Artificial lift system description
- Artificial lift system predictive design
- Fluid properties
- Recent and representative well test
- Static reservoir pressure or fluid level

4
Engineering Basics

This chapter is a review and a source of both material on engineering fundamentals and petroleum engineering correlations that are useful in beam lift calculations. A conversion table is included for those wishing to use SI units (http://physics.nist.gov/cuu/Units/units.html) instead of U.S. units (http://ts.nist.gov/weightsandmeasures/publications/appxc.cfm).

MASS, LENGTH, TIME, AND OTHER MEASUREMENTS

The basic units of measurement are *mass*, *length*, and *time*. All other parameters are combinations of these three base measurements. Other base measurements include electric current [*ampere* (*A*)], temperature [degrees *Kelvin* (*K*)], luminous intensity (*candela* [*cd*)], and amount of material [*gmole* (*mol*)].

Mass

Mass (m or M) is the amount of matter in an object and a physical constant of an object or substance. The unit for mass is *pound-mass* (lb_m) in the U.S. system and *kilograms* (*kg*) in the SI system.

Length

Length (l or L) is the linear measurement of an object, typically the longest dimension. The unit for length is feet in the U.S. system and *metres* (*m*) in the SI system.

Time

Time (t or T) is the interval of an event. The unit for time is *seconds* (*sec*) in both the U.S. and SI systems.

Area

Area (*A*) is the size of a surface in units of L^2. The unit for area is acres for land and $inches^2$ or $feet^2$ for cross sections of pipe or rod in the U.S. system and m^2 in the SI system.

Volume

Volume (*V*) is the capacity of a container or vessel in units of L^3. The unit for volume is $feet^3$, gallons, or barrels in the U.S. system and m^3 in the SI system.

Flow Rate

Flow rate (*q*) is the volume exiting a conduit per unit time in units of L^3/T. The unit for flow rate is $feet^3/sec$, $feet^3/day$, or bbl/day in the U.S. system and m^3/sec in the SI system.

Density

Density (ρ) is the mass of a substance per unit volume in units of M/L^3. The unit for density is lb_m/ft^3 or lb_m/gallon in the U.S. system and kg/m^3 in the SI system.

5
Well Testing

THE PURPOSE OF WELL TESTING

It is not possible, other than by sheer luck, to make an optimal artificial lift system design without an understanding of the flow capability of the well to be produced. Well tests are the simplest and surest way to obtain this understanding. While conducting well tests, it might be possible to uncover problems, including near-wellbore damage (*skin*)[1,2] or problems with the completion such as perforations that are covered with sand or closed because of *scale*. Remedies to these problems might improve the productivity of the well.

The main goal of well testing is to ascertain the maximum production rate that the reservoir can deliver into the bottom of the well on a sustained basis. Additional well testing—involving monitoring the loads on the equipment and the liquid level in the well—is necessary after the installation of the beam-lift equipment. Testing completed after installation is covered in chapters 2 and 11.

Well Test Data to Collect

One or more flow rates from the reservoir and the corresponding pressure at the bottom of the well must be measured while the flow is occurring. It is also necessary to determine the static pressure in the reservoir, but this can be calculated from the well test data and does not necessarily have to be measured directly.

Flow Rates

If the well is still flowing to the surface, it is possible to record the flow rate of oil, water, and gas. A different rate (larger or smaller) can be determined by simply changing the size of the choke in the well. It is important that the flow rate and pressure from the well be allowed to stabilize before the data are accepted. Only stabilized rates and pressures have true meaning when predicting well performance.

If the well has ceased to flow to the surface, some means of artificially lifting the well to obtain representative test data is required. Rates and pressures must be stabilized when testing with artificial lift if reasonable predictions of reservoir performance are to be made.

When rates and pressures are stabilized, liquid rates, gas rates, and pressure cease to change. Many reservoirs that require artificial lift are in a state of continuous pressure decline as fluid is produced from the reservoir. Therefore, even though a rate and a flowing pressure might be stable one day, that rate and pressure could change over time. (Predicting rate and pressure decline is discussed in chapter 1.) So, a stable rate and pressure means that the rate and pressure have stopped changing for the short term. This might take minutes, hours, or even days to establish as the pressure in the well and reservoir adjusts to a different flow rate. The well test must continue at a given rate until the flowing pressure at the bottom of the well ceases to change for the short term, as previously stated. In wells in which the test equipment is capable of more rate than the reservoir can flow into the bottom of the well, the daily output from the

6
The Downhole Pump

This chapter gives details of the basic design and operation of the downhole *plunger pump* commonly used in rod pumping installations, as illustrated in figure 6.1. The system includes a subsurface plunger pump that is axially driven over a linear stroke by a rod string connected to a surface unit that is operated by a prime mover.

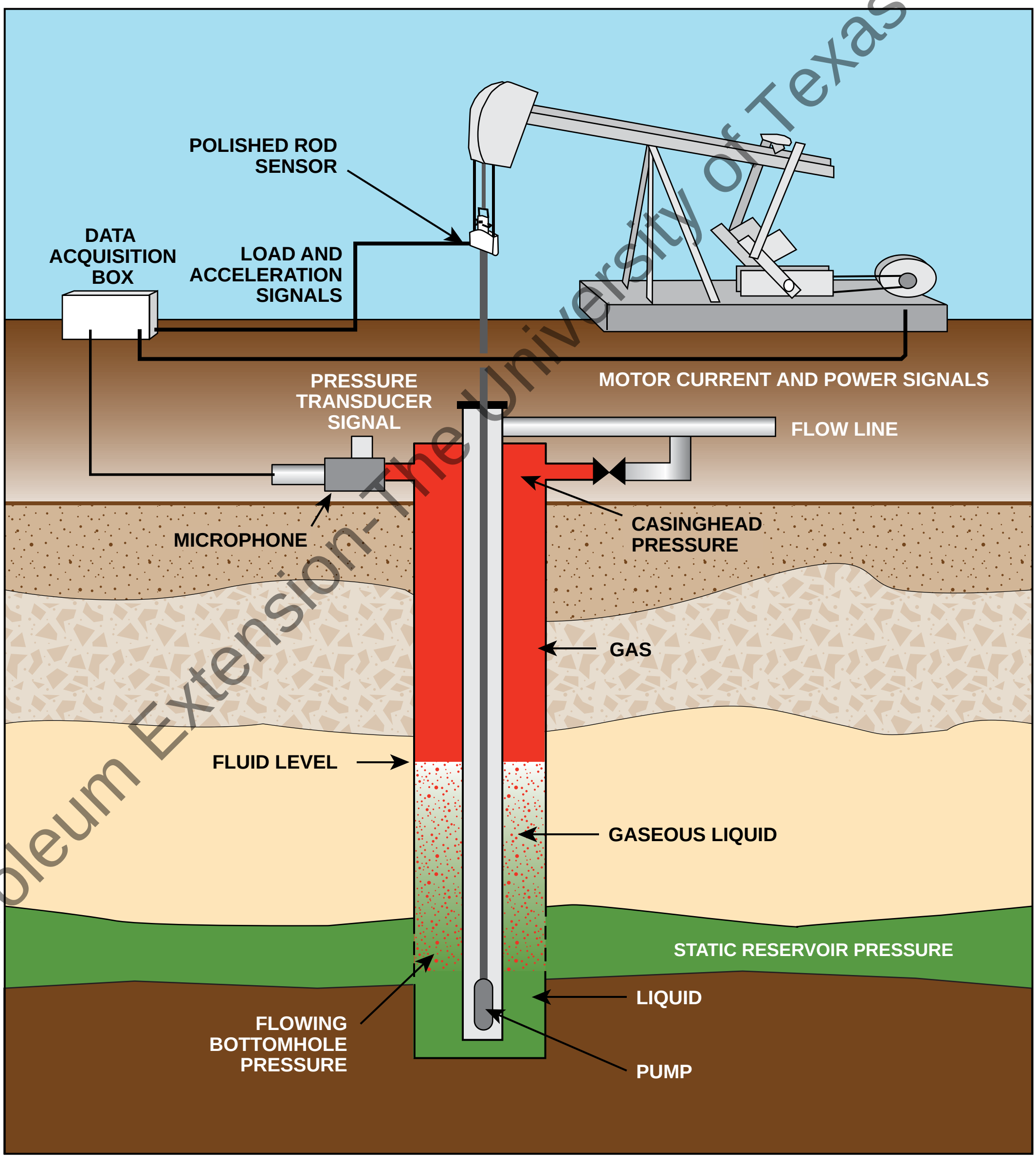


Figure 6.1 The rod pumping system, including wellbore, reservoir, and surface unit

The subsurface pump is attached to a tubing string that delivers the pumped fluids to a surface flow line connected to a *gathering network*. Fluid flows into the wellbore from an underground geologic formation and is driven by the difference in pressure between the wellbore [flowing bottomhole pressure (BHP)] and the pressure in the reservoir away from the well (average reservoir pressure). Fluids entering the wellbore accumulate in the casing and in the annular space between the casing and the tubing and segregate based on their densities; gas percolates to the upper part and liquids accumulate at the bottom. The pump action causes whatever fluid (oil, water, or gas) is present in the wellbore at the depth of the pump intake to be admitted to the pump and then discharged into the bottom of the tubing string for transmission to the top of the well. Gas that reaches the top of the annulus flows out into the surface flow line and mixes with the fluid produced from the *tubing head*.

THE FUNCTION OF THE DOWNHOLE PUMP

To be able to clearly visualize the operation and function of the downhole pump, it is useful to analyze the pressure distribution in the various parts of the pumping system by creating pressure-versus-depth diagrams for the annulus and for the tubing. An example of this type of schematic diagram, called a pressure traverse, is presented in figure 6.2.

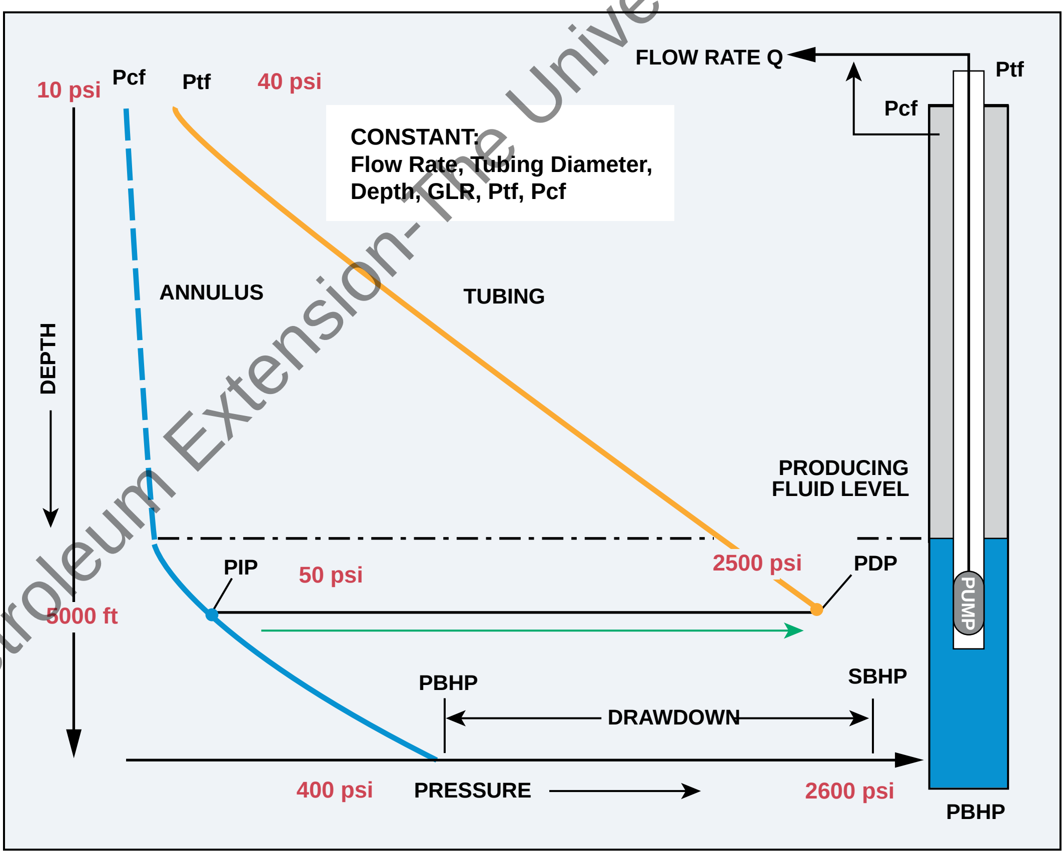


Figure 6.2 Schematic diagram illustrating the pressure-versus-depth traverses in a well produced by pumping

7
Sucker Rods

Sucker rods are jointed steel rods or, in some cases, fiber-reinforced plastic (FRP) rods (also called fiberglass rods) that connect the pump plunger at the bottom of the well to the polished rod that is connected to the pumping unit at the surface. The rods are pulled up through the stroke length by the motion of the pumping unit and fall back into the well on the downstroke as a result of gravity. The objective is to transmit this motion to the pump plunger at the bottom of the well, thereby causing it to move the fluid from the wellbore into the pump barrel and discharge it through the pump into the bottom of the tubing at a pressure that allows the fluid to flow to the surface.

Steel sucker rods are commonly manufactured in lengths of 25 ft, although longer rods are possible. The 25-ft length fits the *working room* in the *derrick* of most *workover rigs*; during trips out of the hole, rods can be hung in triples from the *rod basket*. Figure 7.1 shows a short sucker rod (pony rod) with the parts labeled.

Common rod diameters and weights (including the couplings) for both steel and FRP rods are given in table 7.1.

Table 7.1 shows that FRP rods weigh considerably less than steel rods of the same size. The table also shows that FRP rods have much larger elastic constants than steel rods of the same size.

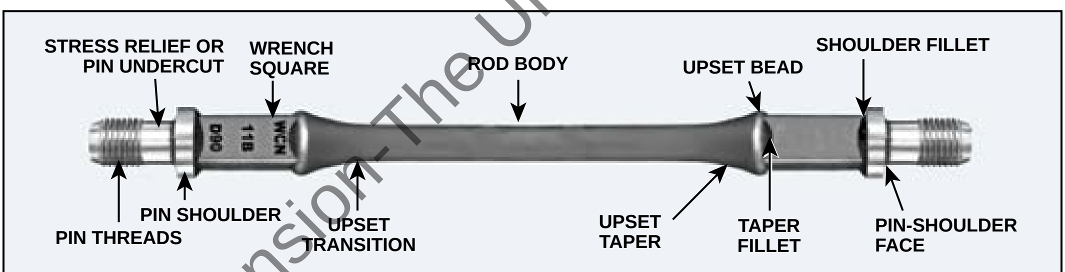


Figure 7.1 Sucker rod terminology

Table 7.1
Sucker Rod Sizes and Elastic Constants

	Steel Rods		FRP Rods	
Diameter (inches)	**Weight (lb_f/ft)**	**Elastic Constant [inches/lb_f(ft)] × 10^{-6}**	**Weight (lb_f/ft)**	**Elastic Constant [inches/lb_f(ft)] × 10^{-6}**
0.5*	0.726	1.99	–	–
0.625*	1.135	1.27	–	–
0.75	1.634	0.883	0.48	4.308
0.875	2.224	0.649	0.64	3.168
1.0	2.904	0.497	0.8	2.425
1.125*	3.676	0.393	–	–
1.25*	4.538	0.318	1.29	1.552
1.5	6.262	0.27	–	–

* = discontinued or limited availability

8
Pumping Units

Pumping units are the machines installed at the surface that lift the rods and fluid the length of the surface stroke at the desired pumping speed. This is the only function of the pumping unit. The rods fall back into the well during the downstroke as a result of gravity. The motion imparted to the rods causes the pump plunger to cycle.

To achieve the function of picking up the rods and fluid for the desired length at the desired speed, the pumping unit must accomplish several associated tasks. First, the pumping unit must be structurally strong enough to support the upstroke and downstroke loads. Second, the pumping unit must convert the rotary motion of the prime mover to the linear motion required at the polished rod. Third, the pumping unit must convert the speed of the prime mover to the desired speed for the pump. And finally, in order to minimize the size and capacity of the pumping unit gear box, the pumping unit supplies a counterbalancing load that offsets a portion of the load being carried by the polished rod.

There are several types of pumping units, the most common of which are the *beam-balanced pumping unit* and the *crank-balanced pumping unit*. Other types are the *long-stroke pumping unit* and the *surface-hydraulic pumping unit*. These types will be discussed in the sections that follow.

BEAM-BALANCED AND CRANK-BALANCED PUMPING UNITS

Beam-balanced and crank-balanced units are the most common types of pumping units. They are robust and, when properly designed and maintained, have service lives of many decades.

Type I Levers

The oldest pumping unit design is the type I lever unit, as shown in figures 8.1 and 8.2. Oilfield applications of this design can be traced back to the early *cable tool rigs*, in which the *walking beam* was used to raise and lower the cable tools while drilling and, afterwards, could be used during production to operate a pump in the well.

The walking beam is a structural steel beam that pivots on a center bearing (sometimes called a *saddle bearing*) on top of a support called the samson post. The samson post provides the pivot point for the lever and the clearance necessary for a given stroke length. These structural components must be strong enough to lift the weight of the fluid and the rods and the additional dynamic loads associated with motion. The beam must support the load and resist bending forces caused by the motion of the unit and the attached loads.

On the front of the walking beam, the *horsehead* serves as the connector for the wire rope *bridle* and carrier bar. The horsehead is curved so that the rods will rise and fall vertically; this keeps the polished rod from bending when the unit is correctly aligned with the wellhead. The polished rod is clamped above the carrier bar using a friction polished rod clamp. The clamp rides on top of the carrier bar and is held in place by the weight carried by the polished rod. The clamp is not secured to the carrier bar in any other way and can separate from the carrier bar during the downstroke if the horsehead is falling faster than the free-fall velocity of the rods into the well.

9

Prime Movers

The power required to start and keep a pumping unit in motion is provided by an external source called a prime mover. Any power source can be used—from windmills and water wheels to steam engines, electric motors, and internal combustion engines. The two most widely used types of prime movers, electric motors and internal combustion engines, are discussed in this chapter.

LOADS CARRIED BY THE PRIME MOVER

When the pumping unit is in motion, the polished rod load is a cyclical load. The cyclical load creates a cyclical torque on the gear reducer and a cyclical load on the prime mover. The gear reducer torque is normally a positive number, but it can also be a negative number, depending on the counterbalance load. A positive torque on the gear reducer requires power from the prime mover to keep the unit in motion. A negative torque on the gear reducer means that the power in the gears is now driving the prime mover. This torque reversal can often be heard in the gear box as an audible clank when the load on the gear teeth moves from the front to the back of the gear teeth. Depending on the pumping loads and the counterbalance required, it might be impossible to eliminate the torque reversal in the gear box. Proper counterbalance combined with pumping speed control (as discussed in chapter 8) will limit the periods and magnitude of negative torque.

If an electric motor is the prime mover, current is delivered to the motor from the transmission line during periods of positive gear reducer torque. During periods of negative torque on the gear reducer, the electric motor is driven as a generator and delivers current back to the line. Some power companies will not issue credit for power delivered back to the line, even though they do receive the power back. To prevent the meters from running backward, power companies place *detents* in the meters.

If an internal combustion engine is being used as the prime mover, the engine will provide power to overcome positive torque in the gear box. During periods of negative torque, the engine is driven by the power coming from the gear box and will speed up as the load on the engine goes to zero. Although not probable, it is possible that the engine can be driven to a speed that will damage the clutch, valves, or rods in the engine. Most engines can survive sizeable *overspeeding* for a few seconds, so damage is not normally an issue.

PRIME MOVER SIZING

The prime mover must be able to supply sufficient power to start the pumping unit from a dead stop and then keep the unit in motion.

Starting Power

The power required to start a unit from a dead stop is related to the torque required at the gear reducer and the inertia that must be overcome in order to accelerate the articulating elements of the unit and the rods to the desired pumping speed. This is impossible to predict in advance

10

Downhole and Wellhead Equipment

THE PUMP INTAKE

A great deal of effort and resources are normally expended in the process of designing the pumping system—selecting the pump, the rod string, the surface unit, the prime mover, etc.—in order to develop a detailed installation plan that is then forwarded to the field crew for execution. However, at the time that the hardware is run into the well, it is unlikely that the designer is present at the site or that a major effort is made to verify that the design plan is implemented without alterations, which might be required due to unforeseen circumstances. These factors often result in inconsistencies between the actual configuration of the pumping system and the recorded description of the hardware that is installed in the well. In particular, there is very little thought and design effort devoted to monitoring the hardware that is installed at or below the pump intake, even though this hardware is perhaps the most important element controlling the efficiency of the pumping system.

The pump can only displace the fluid that is able to enter the barrel through the standing valve (SV). The time available to fill the barrel is on average only a few seconds for the majority of applications (about 3 seconds when pumping at 10 spm, depending on the geometry of the pumping unit). However, the hardware installed below the pump often consists of whatever was used before or whatever was available on location at the time the pump was run. With regard to design, it is recommended that more consideration be given to issues such as filling the pump barrel with liquid and designing the appropriate intake system.

Filling the Barrel With Liquid

In order to achieve efficient operation, the pump intake design objective should be to ensure that every upstroke of the plunger yields a barrel completely filled with liquid. Then, assuming that other losses—such as those resulting from slippage, valve leaks, tubing leaks, etc.—are negligible, the volume of liquid that enters the pump is transferred to the tubing and eventually should be produced at the surface.

The three main causes of incomplete liquid fillage are as follows:

- insufficient inflow from the reservoir to meet pump displacement (pumped-off well)
- restricted inflow due to frictional losses through the pump intake (choked pump)
- flow of a gas–liquid mixture entering through the SV (*gas interference*)

The first of the three causes was addressed as a speed control issue in chapter 8. The other two causes are addressed in this chapter.

Flow Rate Through the SV

Assuming that there is sufficient liquid outside the SV to fill the volume of the barrel at the top of the plunger stroke, the rate at which the liquid has to flow through the pump intake is dependent on the plunger velocity multiplied by the cross-sectional area of the plunger. The velocity of the plunger depends primarily on the pumping speed and the geometry of the pumping unit,

11

Data Acquisition Tools and Data Quality Control

From the time when rod pumping first began to be used in oilfield production operations, it became necessary to understand the performance of the pumping system and the well based on observations and measurements that could be carried out at the surface. This understanding included qualitative visual and auditory observations and quantitative measurements of mechanical, pressure, and flow variables related to the pumping cycle. Knowledge of the position of the wellbore fluid relative to the depth of the pump intake was also required in order to evaluate the performance of the artificial lift system. Two sets of tools were developed early on and refined over time to achieve these goals: the dynamometer and the *acoustic fluid level instrument*.

DYNAMOMETER

The dynamometer generates a dynagraph, which is a "record of the forces existing at the top of the rod system with respect to the stroke cycle"[1].

The force at the top of the rods is the sum of all the effective forces that result from the forced motion of the polished rod by the cyclical movement of the pumping unit. This includes forces applied by the downhole pump to the rods, friction forces, inertial forces, vibration forces, buoyancy, and others as they exist at any point during the pumping cycle.

Objective of Dynamometer Measurements

The objective of analyzing the dynamometer graph is to understand and to visualize the performance of the pumping system. This analysis can be divided into two main tasks, as follows:

- The loads applied to the mechanical elements of the system are analyzed. This includes a study of the loading of the surface unit, gear reducer, power transmission, and prime mover, and the mechanical loading of the rod string.
- The performance of the downhole pump is analyzed. This includes pump volumetric efficiency, operation of the valves, liquid fillage, plunger travel, leakage, etc.

The first part of the objective is achieved by transforming the forces measured at the polished rod to the corresponding forces, torque, or stresses that are developed at the various points in the mechanical system. This requires having a detailed description of the pumping unit's geometry, gear box capacity, transmission, motor, rod string, etc.

The second part of the objective is achieved by transforming the measured load and position of the polished rod to the load and position of the pump plunger, which is achieved by accounting for the elasticity and dynamics of the rod string.

Accurate measurement of the polished rod load and position is a requirement for quantitative analysis of dynamometer records. However, some insight into the operation of the pumping system can be achieved through inspection of qualitative dynamometer cards, based on the prior experience of the analyst.

12
Design Methods

Please note that this chapter is not a recommendation for any particular commercial service or design software. Instead, it is a reference source, a discussion of and a comparison between design methods, new and old.

PREDICTIVE METHODS

Predictive methods are mathematical models based on assumed pump conditions that estimate, at a minimum, the loads on the rods and pumping unit and the necessary counterbalance, gear box size, and prime mover power for the pumping unit. The rod stress fluctuation is then plotted on the American Petroleum Institute (API) Modified Goodman Diagram (MGD) in order to make sure that the rod loads are at or below the recommended maximum loading. Some computer programs can include the influence of wellbore deviation and other pump fillage anomalies in order to predict the shape of the surface dynamometer card.

The fundamental data set necessary to estimate the rod loads, pumping unit size, and power requirement includes the following:

- Q = desired surface liquid production rate (STB/day)
- B_o = oil formation volume factor (bbl/STB)
- γ_f = fluid specific gravity (relative to fresh water)
- μ_f = fluid viscosity at pump intake conditions (cp)
- L = pump setting depth (ft from the surface)
- L_n = working fluid level or net lift (ft from the surface)
- S = surface stroke length (inches)
- D_p = pump plunger diameter (inches)
- C = plunger–barrel clearance (inches)
- L_p = plunger length (ft)
- e = pump volumetric efficiency (fraction ≅ 0.9)
- D_t = tubing internal diameter (inches)
- d_i = rod diameters in the rod string (inches)
- Pumping unit type = type I or III lever

The initial estimate for pumping speed can be obtained using equation 12.1.

$$N = \frac{QB_o}{0.1166eD_p^2S} \qquad \text{Eq. 12.1}$$

N = pumping speed (spm)

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To obtain additional training materials, contact:

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Austin, TX 78758

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