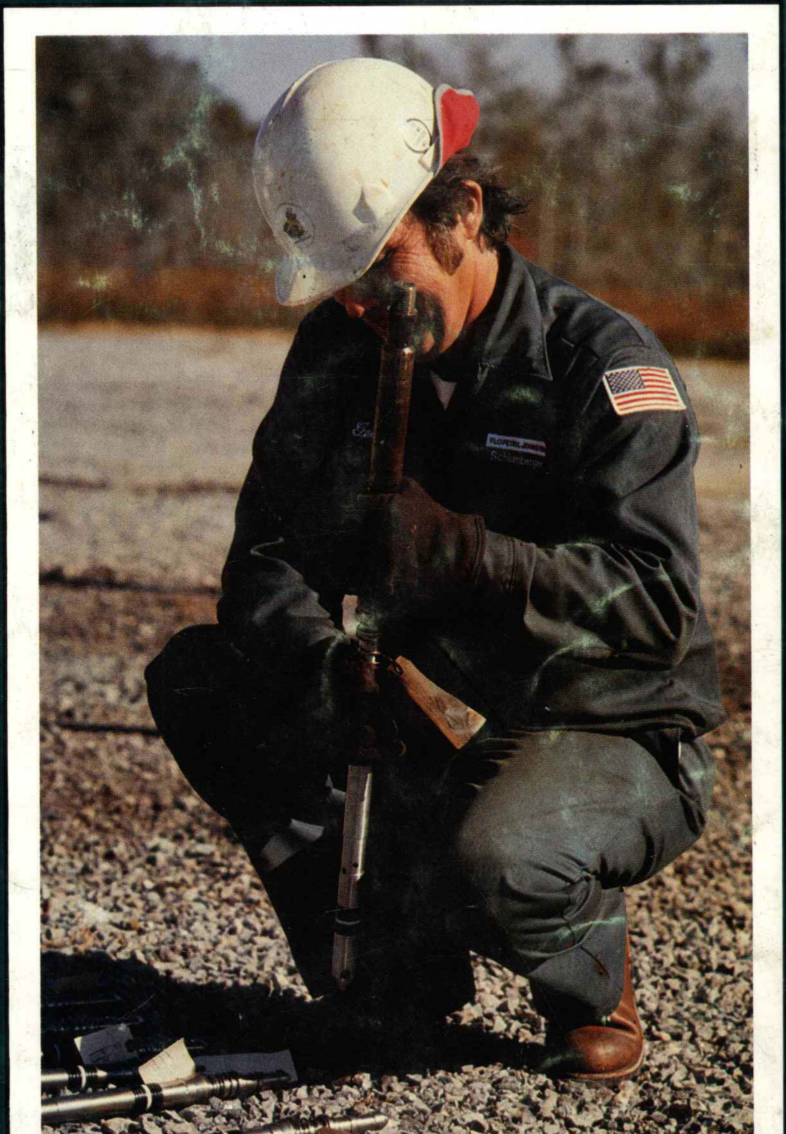
Artificial Lift

OIL AND GAS PRODUCTION



PETEX

OIL AND GAS PRODUCTION

Artificial Lift

by
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Foreword

Artificial Lift is one of a series of study lessons covering appropriate topics in oil and gas production. As with other lessons, this one is intended to contain information presented during lecture sessions of the API-sponsored School of Production Technology.

The manual is intended to be an overview of the artificial lift programs now being used to produce oil from wells that have diminished or ceased flow by means of natural pressure in the reservoir. It covers design considerations in planning any program of artificial lift and a brief description of each program—gas lift, plunger lift, sucker rod pumping, hydraulic pumping, and electric submersible pumping. According to its aim, it does not describe any of the programs in depth, but instead provides the reader with a look at the variety of programs available at present.

The material presented in this book has been reviewed by a number of industry specialists including various members of the API Advisory Committee for the School of Production Technology, as well as instructors of that school. Striving to meet the educational needs of the petroleum industry, we welcome comments from the users of any of our training materials. In particular, we invite information concerning the relevancy of the material presented to current practices in the field.

Curtis Kruse, Director
Petroleum Extension Service

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Companies and individuals were helpful in providing illustrations or permission to reproduce illustrations, and to them we also wish to express thanks.

How to Use This Manual

The format of this manual includes a set of specific objectives for each section; at the end of the section is a competency self-test. To get maximum benefit from the manual, read the specific objectives carefully before studying the material in each section. As you study the material in the section, take notes, using the objectives as a guide to the most important parts.

When you feel that you have mastered the objectives, begin the self-test. Since it is a self-test, *you* decide whether you should refer back to the material to answer the questions by determining how important that section is to your work. If you feel that you need to be very competent in an area, do not refer back until you have finished the test. This way, using the scoring points given at the beginning of the test, you can determine your percentage of competency. Score the test by using the corresponding key provided at the end of this manual.

Table of Contents

1

Planning an Artificial Lift Program

OBJECTIVES

Upon completion of this section, the student will be able to:

1. Explain the principle of artificial lift.
2. List the factors to be considered in designing an artificial lift program.
3. Explain the relationship between reservoir engineers and operating personnel in assessing and predicting reservoir performance.
4. Explain how the inflow capability of a well is evaluated (PI and IPR curve methods).
5. Explain how the outflow of a well is related to getting the desired rate of production from a well.
6. Realize the importance of minimizing downtime and lost production in obtaining economic gain from a well.

PRINCIPLE OF ARTIFICIAL LIFT

With the exception of very shallow reservoirs, a well completed in a new reservoir will usually flow, the energy for production coming from pressure in the reservoir. Over time, however, natural reservoir pressure will drop, and the well will eventually cease to flow, leaving a great deal of recoverable oil still in place. Artificial lift is a means of furnishing the power necessary to bring that oil to the surface.

Of the many wells on artificial lift in the U.S. today, over 10 percent utilize gas lift; another 85 percent, sucker rod pumping. The rest of U.S. artificial lift is done by using hydraulic pumps, electric submersible pumps, and plunger lift.

DESIGN CONSIDERATIONS

Factors to Be Considered

Selecting the method of artificial lift, designing its installation, and maintaining productivity in the face of ever-changing well conditions requires careful attention to several different factors.

Reservoir characteristics are the first consideration. Porosity, permeability, the presence of sand, and fluid saturation of the formation all affect the ability of the oil to flow into the well. Formation pressure and temperature must also be considered.

Reservoir drive—the natural force that brings on the flow of oil from a well—determines reservoir performance, or the changing activity below the surface that has a great deal to do with productivity. Types of drive are (1) water, (2) solution gas, (3) gas cap, and (4) combination.

Properties of the oil itself—density, viscosity, paraffin content, and shrinkage—must also be taken into account, as must the *properties of the formation water*—density, scaling tendencies, and corrosiveness—and *properties of the gas*—density, viscosity, and corrosiveness.

Inflow and outflow characteristics of the well must be of great concern in determining an artificial lift method. These characteristics include the productivity index (PI), the gas-liquid ratio over the life of the well, the water cut over the life of the well, and well diameter and depth.

Well completion data are used in designing an artificial lift program. Such data include (1) reservoir depth, (2) reservoir thickness, (3) type of completion, (4) completion interval, (5) casing size, (6) tubing size, and (7) hole deviation.

The *power available* must also be considered in any design—that is, whether high-pressure gas-lift gas, fuel gas, or electricity is at hand.

Field data must be considered—field location, number of wells, access to the field, and existing facilities.

Legal restrictions—lease requirements, environmental requirements, and production regulations—are of importance in planning any program, because their influence may be very great.

Finally, an *economic evaluation* of any program is indispensable. It must include the concept of the time value of money as well as operation and maintenance costs.

Three of these design considerations—reservoir performance, inflow characteristics of a well, and outflow characteristics of a well—merit special discussion, as does the consideration of costs.

Reservoir Performance

The productivity and character of fluids produced from a well may be expected to change throughout the life of the well,

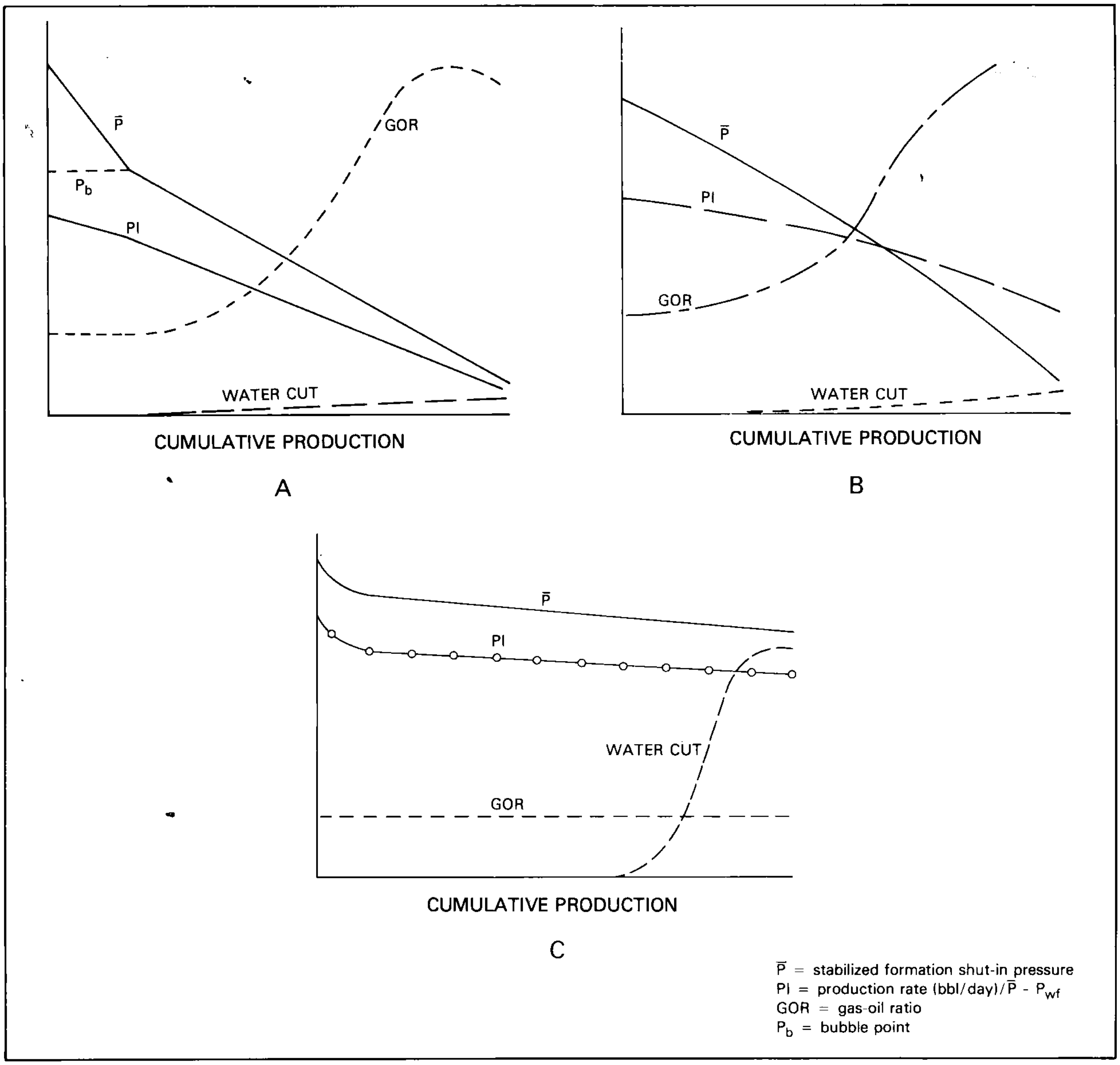

Figure 1. Comparison of production curves for (*A*) solution-gas drive, (*B*) gas-cap drive, and (*C*) water drive.

depending upon the type of reservoir drive (fig. 1). The curves shown are fairly simplistic in nature, as actual reservoirs may have more than one type of drive or other peculiarities that cause deviations from the performance expected from a particular type of drive. For example, a reservoir with solution-gas drive might have a maximum recoverability of from 5 to 30 percent of the original oil in place. Expected recovery from a reservoir with gas-cap drive might be from 20 to 40 percent and from a water-drive reservoir, from 35 to 80 percent. Of course, ultimate recoveries can be improved by various methods.

Reservoir engineers not only furnish operating personnel with predictions of well performance based upon data available at completion but also update their predictions periodically on the basis of actual production, well test data, and pressure surveys. For maximum economic gain, interdependence of reservoir engineers and operating personnel is necessary. Operating personnel cannot make adjustments in production methods to follow changes in well characteristics without knowing what the well's producing characteristics should be. And reservoir engineers, to provide reliable assessments and predictions of downhole conditions, must receive accurate production, well test, and pressure data from the operating group.

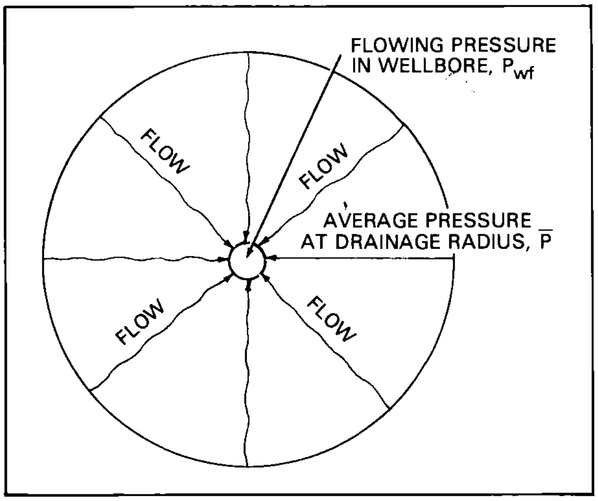

Figure 2. Plan view of single-phase liquid radial flow into a wellbore

Well Inflow Characteristics

The inflow capability of a well is probably one of the most important considerations in designing an artificial lift system. Obviously, nothing can be produced from a wellbore if nothing can flow from the reservoir into the wellbore. What flows into a wellbore depends upon the characteristics of both the reservoir and its fluids. It also depends upon the characteristics of the completion and the conditions of the wellbore while it is producing. All of these may undergo changes throughout the life of the well. The operator can do little about some changes that reduce production, but has direct control over others.

If a well completion does not restrict the flow of formation fluids from a well, then the flow of liquid only—single-phase flow—from the reservoir into the wellbore is directly proportional to the difference between the formation stabilized pressure ($\overline{P}$) and the wellbore pressure at the formation (P_{wf}) (fig. 2). This difference is also referred to as *drawdown.* Production for single-phase radial flow from a reservoir into a wellbore is expressed mathematically as follows:

$$\text{Production} = PI\,(\overline{P} - P_{wf}) = \text{bbl/day}$$

where

PI = productivity index (a constant) = bbl/day/psi.

Accordingly, for a well producing 200 bbl of oil per day with a stabilized bottomhole shut-in pressure of 4,000 pounds per square inch absolute (psia) and a stabilized bottomhole flowing pressure of 3,000 psia (fig. 3), the productivity index would be calculated as follows:

$$PI = \frac{\text{production}}{\overline{P} - P_{wf}}$$

$$= \frac{200}{4{,}000 - 3{,}000}$$

$$= 0.2 \text{ bbl/day/psi.}$$

In this example, if bottomhole flowing pressure (P_{wf}) is reduced to 2,000 psia, then production would be 400 bbl/day. At 1,000 psia, production would increase to 600 bbl/day.

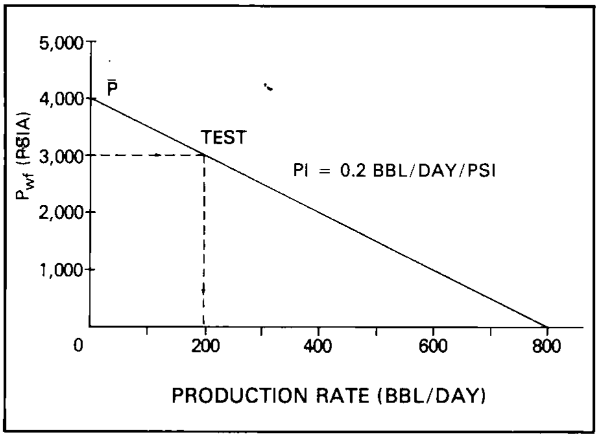

Figure 3. Productivity curve for single-phase liquid flow

PI is affected by the characteristics of the reservoir and its fluids. One such characteristic, permeability, is of particular importance. Lowered permeability, as a result of silt, scale, or paraffin deposits around the wellbore, tends to lower the productivity index. Conversely, increased permeability from acidizing or fracturing causes an increase in the productivity index (fig. 4).

The example shown in figure 4 is based on single-phase liquid flow. In many cases the oil flowing into the wellbore is near or below its bubble point (P_b), the pressure at which gas will start to bubble out of the oil.

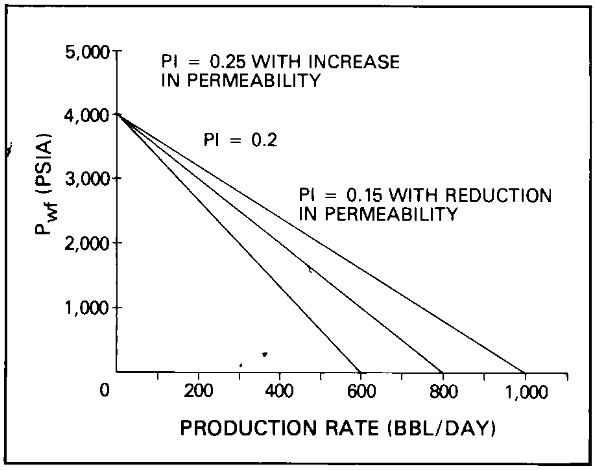

Figure 4. Changes in productivity with changes in permeability

For example, with a stabilized bottomhole shut-in pressure ($\bar{P}$) of 4,000 psi and a crude oil having a bubble point (P_b) of 3,000 psi, bottomhole flowing pressure (P_{wf}) can be reduced from 4,000 psi to any level greater than 3,000 psi and still maintain single-phase flow into the wellbore. But if P_{wf} is reduced below 3,000 psi, two-phase flow (liquid and gas flow) will result. As P_{wf} is reduced, a greater amount of gas and a smaller amount of oil are produced per psi of pressure drop (fig. 5). Such a productivity curve based on well tests or a combination of computations and well tests is called an *inflow performance relationship* (IPR) curve.

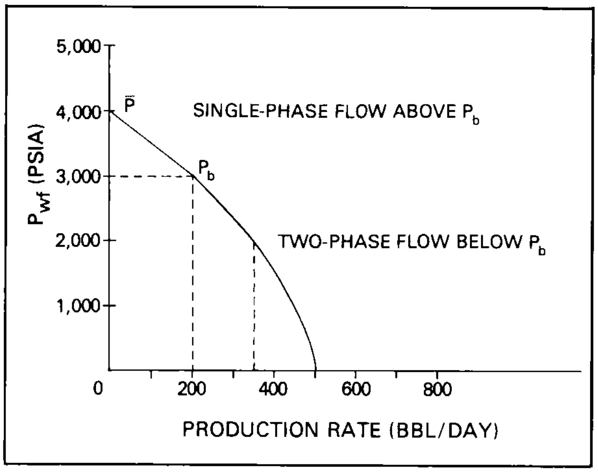

Figure 5. Productivity curve for a well with crude having a bubble point of 3,000 psi

For evaluating well performance, the PI curve method is used for single-phase liquid flow, and the IPR curve method is used for two-phase flow. Using figure 5 as an example, the PI would be used at values of P_{wf} above 3,000 psi, and the IPR curve would be used for values of P_{wf} below 3,000 psi.

Well Outflow Characteristics

To get the desired rate of production from a well, stabilized bottomhole producing

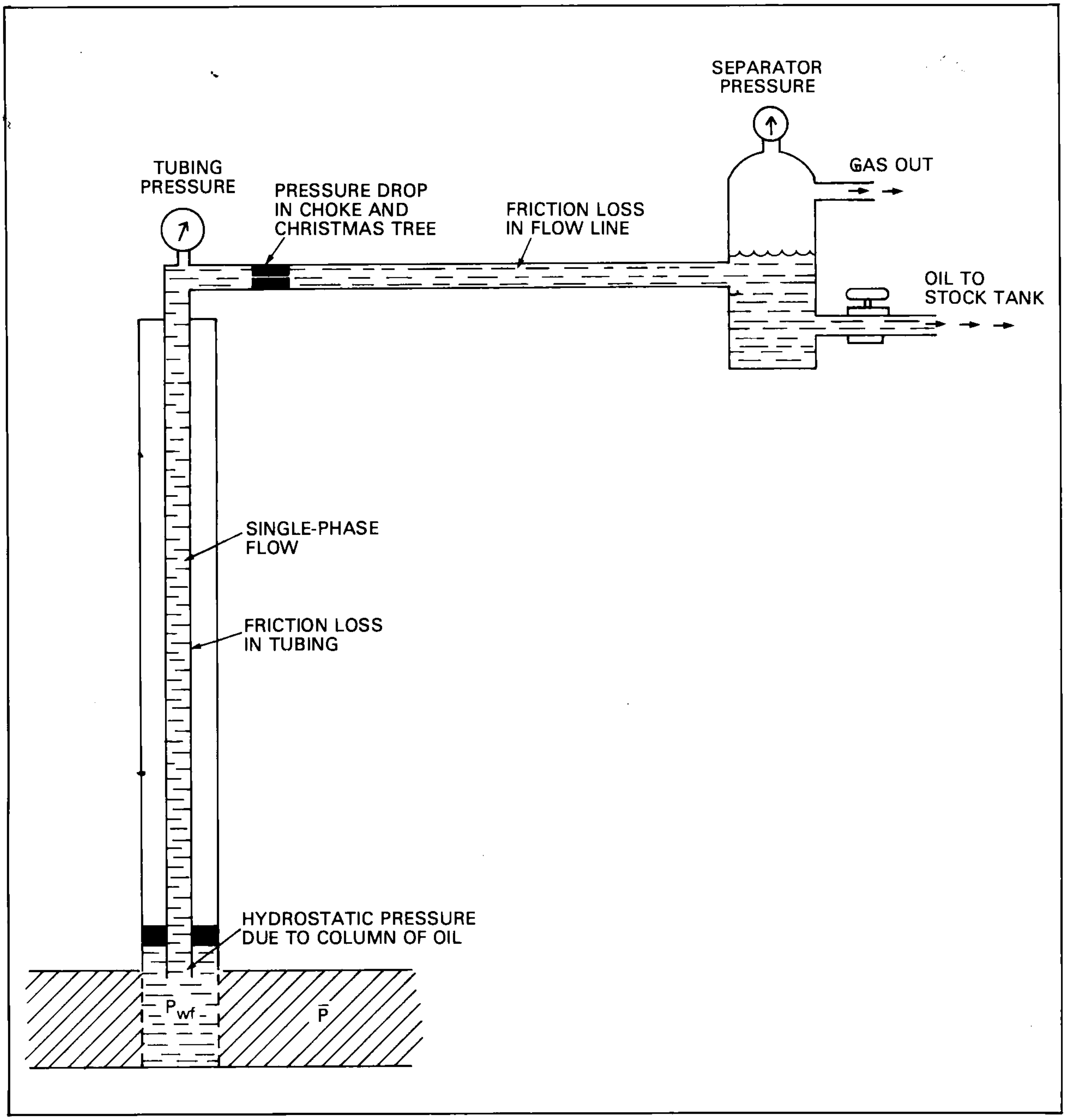

Figure 6. Outflow system for a single-phase flowing well

pressure (P_{wf}) must be reduced to the level required by the inflow characteristics. The level to which P_{wf} can be reduced depends on the outflow characteristics of the well. *Outflow* refers to the flow system between the bottom of the hole and the stock tanks.

In the simplest and rarely occurring system, where the well is flowing with single-phase liquid throughout (fig. 6), P_{wf} is determined by the hydrostatic pressure of the fluid column, friction losses in the system, and back-pressure on the surface separator. From figure 6, P_{wf} would be calculated as follows:

P_{wf} = hydrostatic pressure + friction loss in tubing + friction loss in choke and Christmas tree + friction loss in flow line + separator pressure, or

P_{wf} = hydrostatic pressure + friction loss in tubing + tubing pressure

where

Tubing pressure = friction loss in choke and Christmas tree + friction loss in flow line + separator pressure.

With single-phase flow these values can be easily predicted for a set flow rate by using relatively simple calculations. Hydrostatic pressure varies directly with the fluid density and the depth of the well. Since a single-phase liquid is relatively incompressible, fluid density is considered to be constant from the top of the well to the bottom. Friction loss in the tubing increases with the fluid's increasing viscosity, decreases with increasing tubing size, and increases with the increasing friction factor of the pipe and the flow rate.

The simple situation presented for illustration purposes in figure 6 would seldom occur. With oil at or near its bubble point, the gas that comes out of solution in the lower part of the well expands greatly at the reduced pressure, often to several hundred times its volume at the bottom of the well (fig. 7). Accurate predictions of either hydrostatic pressure or friction loss are difficult to make in this situation. The addition of water to the fluid flow or the introduction of an artificial lift system further complicates attempts to predict the effects of the outflow system on well production. However, by increasing tubing or line sizes and decreasing the number of bends, line lengths, and separator pressure, P_{wf} can often be reduced, thereby increasing the well's productivity regardless of the fluid being produced.

The PI and IPR curves can also be used to match the characteristics of the outflow

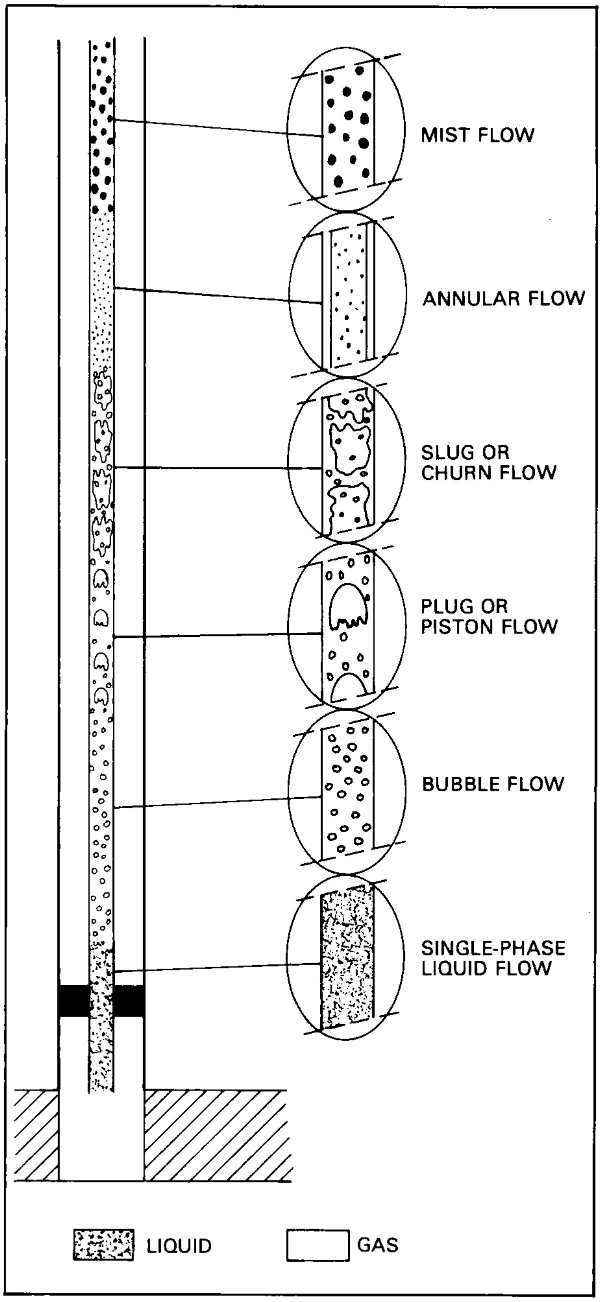

Figure 7. Regimes of vertical two-phase flow (Courtesy of Shell)

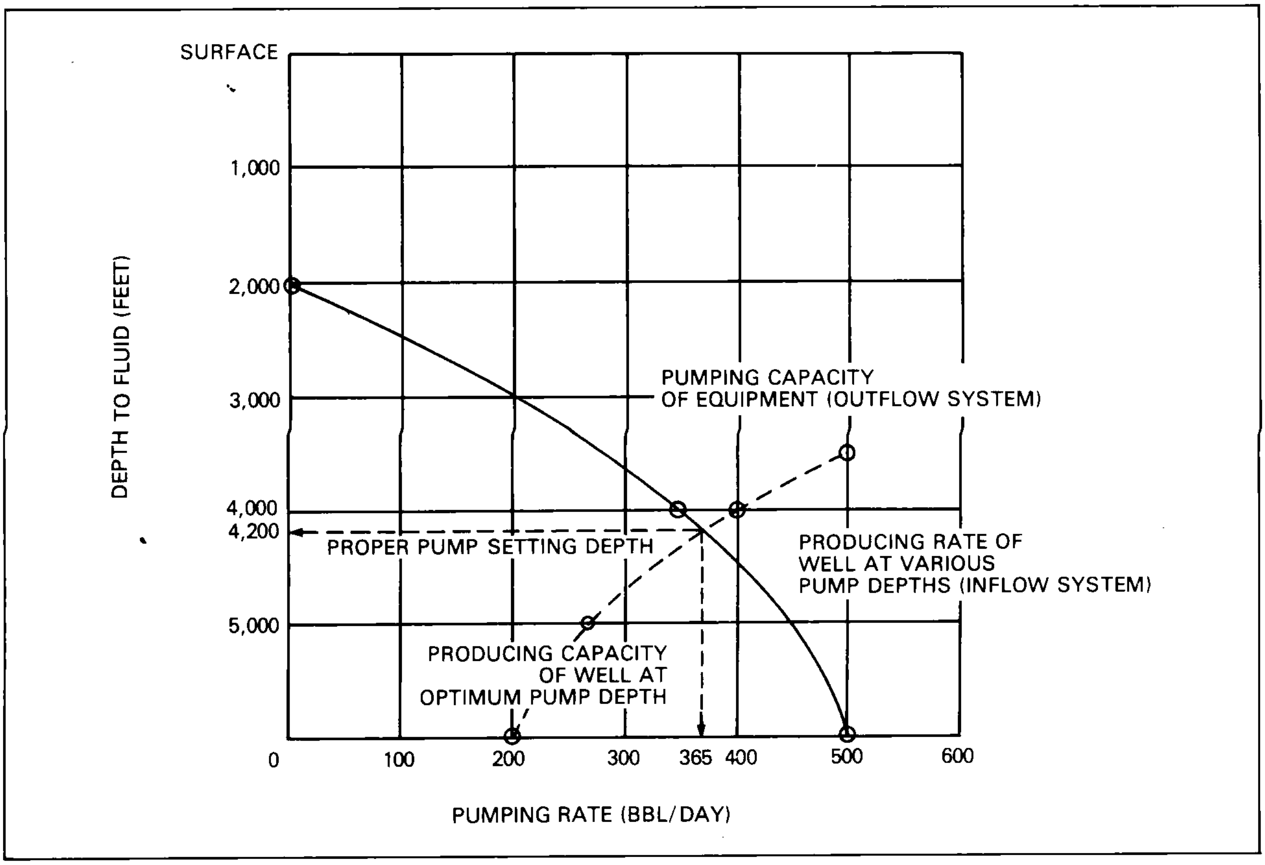

Figure 8. Well producing capacity and pumping equipment capacity vs. depth (Courtesy of Echometer)

system to the well's performance characteristics (fig. 8). In this example, drawdown for a pumping well is plotted against pumping depth. The well's producing capacity increases with drawdown, but the capacity of the pumping unit on the well decreases with pump setting depth. The proper setting depth is 4,200 feet, at which 365 bbl/day are produced. For higher production rates, a larger pumping unit and greater pump setting depth would be needed.

Cost Considerations

Achieving the maximum economic gain in oil production must take into account the time value of money. Savings accounts are a familiar example of the principles involved. One dollar placed in savings at 10% compounded annually will grow to be worth $2.59 in ten years. The same dollar invested at 15% compounded annually would be worth $4.05 in ten years. Conversely, $4.05 received ten years from now is worth only 1 dollar today at a 15% compounded annual interest rate.

Determining present value of future dollars is called *discounting,* or compounding in reverse. The present worth of a dollar at some future date is the reciprocal of the future value of a dollar invested today for the same length of time, at the same rate, and with the same compounding interval.

Design engineers use this concept to determine the most economical production method for a given well. From an operating

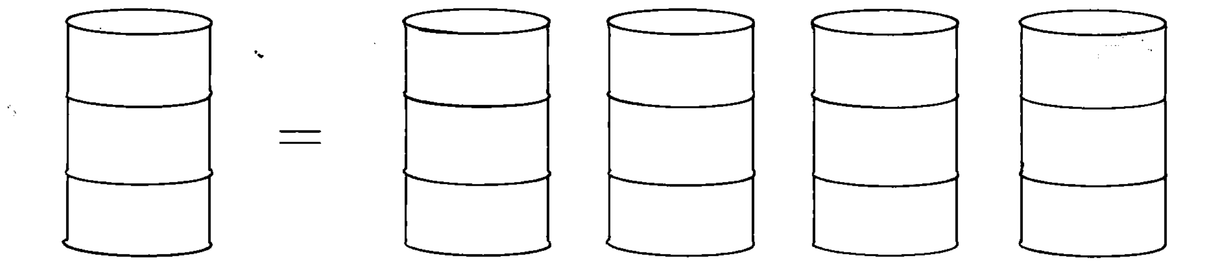

Figure 9. Present worth of future production

standpoint, an understanding of this concept helps to realize the cost of downtime and the importance of correcting problems that impede maximum production. If a well in a field with a life expectancy of ten years is off production, losses may not be recovered for ten years. At an interest rate of 15% compounded annually and with constant oil prices, this production is worth only one-fourth of what it would be if it were produced today (fig. 9). *One of the most important factors in obtaining the maximum economic gain from a well is to minimize downtime and lost production.*