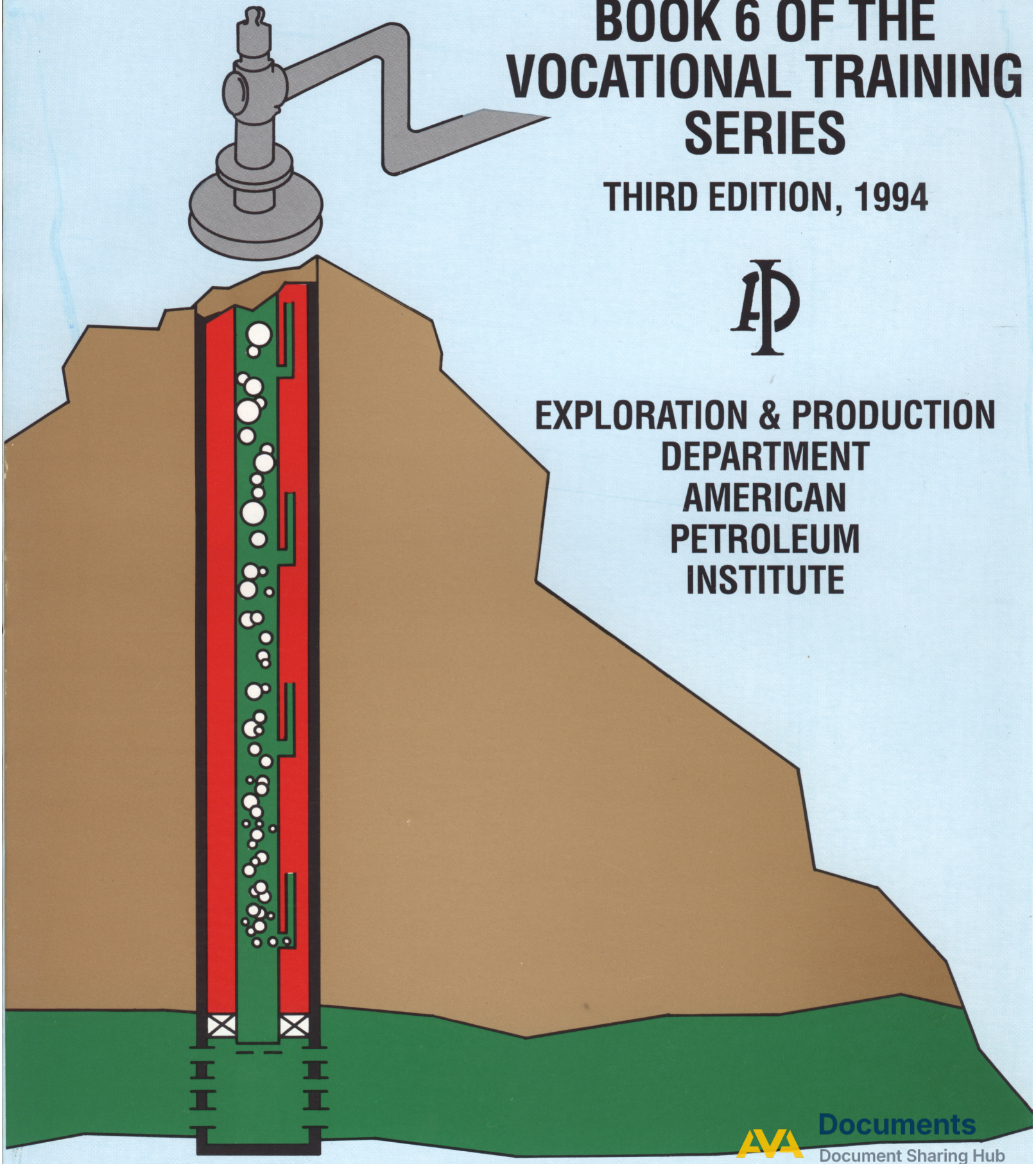
GAS LIFT

BOOK 6 OF THE VOCATIONAL TRAINING SERIES

THIRD EDITION, 1994



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API GAS LIFT MANUAL

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FOREWORD

Artificial lift represents an increasingly important part of the oil business. In fact, at the time of this writing, over 90% of the oil wells in the United States used some form of artificial lift. The four basic types of artificial lift used in the oil industry are: rod pumping, electric submersible pumping, hydraulic pumping, and gas lift. As the name implies, gas lift is the only one of the artificial lift systems that does not use some form of mechanical pump to physically force the fluid from one place to another. Because of this phenomenon, gas lift has certain advantages over the other systems in some instances and occupies a rather unique and important place as a lift mechanism.

This manual is under the jurisdiction of the Executive Committee on Training and Development, Exploration & Production Department, American Petroleum Institute. It is intended to familiarize operating personnel with the use of gas lift as an artificial lift system. It includes information on the basic principles of gas lift, the choice of gas lift equipment, how various types of gas lift equipment work, and how a gas lift system should be designed. Information is also included on monitoring, adjusting, regulating, and trouble-shooting gas lift equipment.

The first edition of this manual was issued in 1965. A second edition was issued in 1984, and editorial errata were published in 1986 and incorporated in a 1988 reprint of the manual. This third edition was developed as an editorial update for consistency with recent API gas lift standards.

It was developed with assistance by volunteer technical reviewers including:

J. R. Blann, Consultant, Lead Reviewer
J. R. Bennett, Exxon Production Research Company
Joe Clegg, Pectin International
John Martinez, Production Associates
H. W. Winkler, Consultant

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Other publications in the API Vocational Training Series are:

Book 1: *Introduction to Oil and Gas Production*, Fourth Edition, 1983 (Reaffirmed 1988)

This popular orientation manual contains 81 pages and over 100 photographs and line drawings. It is written as a simple, easy-to-understand style to help orient and train inexperienced oil and gas production personnel. The book is also helpful to students, industry office personnel, and businesses allied with the oil and gas industry. The fourth edition represents a complete revision and updating of the previous edition. Spiral bound, $8^1/_2$ x 11, soft cover.

Book 2: *Corrosion of Oil and Gas Well Equipment*, Second Edition, 1990

General aspects of corrosion, sweet corrosion, oxygen corrosion, and electrochemical corrosion are thoroughly covered. Methods of evaluation and control measures are described in detail Spiral bound, $6^1/_2$ x 10, soft cover, 87 pages.

Book 3: *Subsurface Salt Water Injection and Disposal*, Second Edition 1978 (Reaffirmed 1986)

A handbook for the planning, installation, operation, and maintenance of subsurface injection and disposal systems. Design criteria and formulae are given for gathering systems, treating plants, and injection facilities. Alternative equipment and methods are discussed and illustrated. Economic considerations are presented. The book includes a glossary and bibliography. Soft cover, $6^1/_2$ x 10, spiral bound, 67 pages, 18 illustrations.

Book 5: *Wireline Operations and Procedures*, Second Edition, 1983 (Reaffirmed 1988)

This handbook describes the various surface and subsurface wireline tools and equipment used in the oil and gas industry. It explains and outlines the application of these tools in wireline operations, including those operations conducted offshore. It is a basic manual presented in a simple, uncluttered manner. Soft cover, 72 pages, 90 illustrations, $6^1/_2$ x 10, spiral bound.

API Specs & RPs

(Users should check the latest editions)

Spec 11 V1, *Specification for Gas Lift Valves, Orifices, Reverse Flow Valves and Dummy Valves*

Covers specifications on gas lift valves, orifices, reverse flow valves, and dummy valves.

RP 11V5, *Recommended Practice for Operation, Maintenance, and Trouble-Shooting of Gas Lift Installations*

Covers recommended practice on kickoff and unloading, adjustment procedures and trouble-shooting diagnostic tools and location of problem areas for gas lift operations.

RP 11V6, *Recommended Practice for Design of Continuous Flow Gas Lift Installations Using Injection Pressure Operated Valves*

This recommended practice is intended to set guidelines for continuous flow gas lift installation designs using injection pressure operated valves. The assumption is made that the designer is familiar with and has available data on the various factors that affect a design. The designer is referred to the API "Gas Lift Manual" (Book 6 of the Vocational Training Series) and to the various API 11V recommended practices on gas lift.

RP 11V7, *Recommended Practice for Repair, Testing and Setting Gas Lift Valves*

This document applies to repair, testing, and setting gas lift valves and reverse flow (check) valves. It presents guidelines related to the repair and reuse of valves; these practices are intended to serve both repair shops and operators. The commonly used gas pressure operated bellows valve is also covered. Other valves, including bellows charged valves in production pressure (fluid) service should be repaired according to these guidelines.

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CHAPTER 1
INTRODUCTION TO ARTIFICIAL LIFT AND GAS LIFT

BASIC PRINCIPLES OF OIL PRODUCTION

When oil is first found in the reservoir, it is under pressure from the natural forces that surround and trap it. If a hole (well) is drilled into the reservoir, an opening is provided at a much lower pressure through which the reservoir fluids can escape. The driving force which causes these fluids to move out of the reservoir and into the wellbore comes from the compression of the fluids that are stored in the reservoir. The actual energy that causes a well to produce oil results from a reduction in pressure between the reservoir and the producing facilities on the surface. Fig. 1-1 illustrates this production process as it occurs in an oil well. If the pressures in the reservoir and the wellbore are allowed to equalize, either because of a decrease in reservoir pressure or an increase in wellbore and surface pressure, no flow from the reservoir will take place and there will be no production from the well.

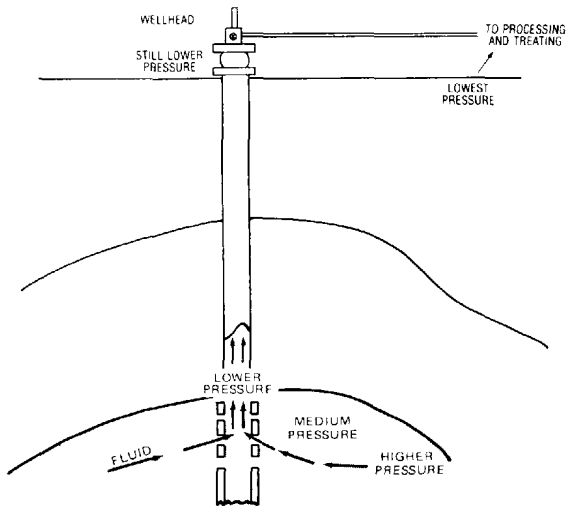


Fig. 1-1 — The production process in an oil well

Factors That Affect Oil Production

There are a number of factors which affect the producing characteristics of an oil well. These factors are often interrelated and may include such things as fluid properties of the oil itself, amount of gas and water associated with the oil, properties of the reservoir, size of the producing pipe and related subsurface equipment, and the size and length of the flowline connecting the well to production facilities. All of these factors play an important part in an oil well's performance and must be carefully considered when the installation is designed. An ideal production installation makes maximum use of the natural energy available from the reservoir.

ARTIFICIAL LIFT

In many wells the natural energy associated with oil will not produce a sufficient pressure differential between the reservoir and the wellbore to cause the well to flow into the production facilities at the surface. In other wells, natural energy will not drive oil to the surface in sufficient volume. The reservoir's natural energy must then be supplemented by some form of artificial lift.

Types of Artificial Lift Systems

There are four basic ways of producing an oil well by artificial lift. These are *Gas Lift, Sucker Rod Pumping, Submersible Electric Pumping* and *Subsurface Hydraulic Pumping*. The surface and subsurface equipment required for each system is shown in Fig. 1-2.

Choosing an Artificial Lift System

The choice of an artificial lift system in a given well depends upon a number of factors. Primary among them, as far as gas lift is concerned, is the availability of gas. If gas is readily available, either as dissolved gas in the produced oil, or from an outside source, then gas lift is often an ideal selection for artificial lift. Experience has shown that produced gas will support a gas lift system if the daily gas rate from the reservoir is at least 10% of the total circulated gas rate. No other system of artificial lift uses the natural energy stored in the reservoir as completely as gas lift. If an installation is adequately designed, wells can be gas lifted over a wide range of producing conditions by regulating the injection gas volume at the surface.

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THE PROCESS OF GAS LIFT

Gas lift is the form of artificial lift that most closely resembles the natural flow process. It can be considered an extension of the natural flow process. In a natural flow well, as the fluid travels upward toward the surface, the fluid column pressure is reduced, gas comes out of solution, and the free gas expands. The free gas, being lighter than the oil it displaces, reduces the density of the flowing fluid and further reduces the weight of the fluid column above the formation. This reduction in the fluid column weight produces the pressure differential between the wellbore and the reservoir that causes the well to flow. This is shown in Fig. 1-3(A). When a well produces water along with the oil and the amount of free gas in the column is thereby reduced, the same pressure differential between wellbore and reservoir can be maintained by supplementing the formation gas with injection gas as shown in Fig. 1-3(B).

Types of Gas Lift

There are two basic types of gas lift systems used in the oil industry. These are called continuous flow and intermittent flow.

Continuous Flow Gas Lift

In the continuous flow gas lift process, relatively high pressure gas is injected downhole into the fluid column. This injected gas joins the formation gas to lift the fluid to the surface by one or more of the following processes:

1. Reduction of the fluid density and the column weight so that the pressure differential between reservoir and wellbore will be increased (Fig. 1-4A).

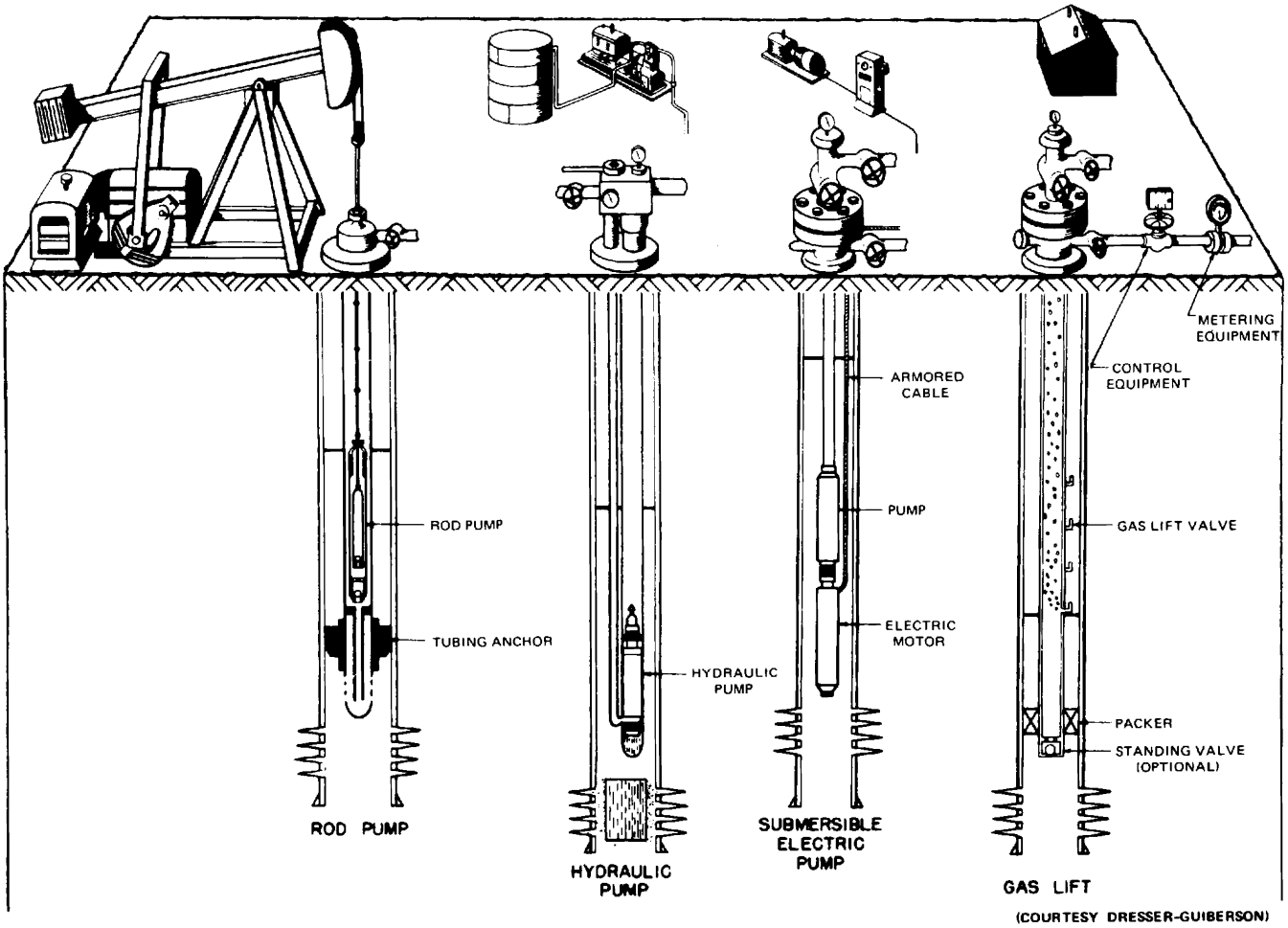


Fig. 1-2 — Artificial lift systems

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2. Expansion of the injection gas so that it pushes liquid ahead of it which further reduces the column weight, thereby increasing the differential between the reservoir and the wellbore (Fig. 1-4B).
3. Displacement of liquid slugs by large bubbles of gas acting as pistons (Fig. 1-4C).

A typical small continuous flow gas lift system is shown in Fig. 1-5.

Intermittent Flow Gas Lift

If a well has a low reservoir pressure or a very low producing rate, it can be produced by a form of gas lift called intermittent flow. As its name implies, this system produces intermittently or irregularly and is designed to produce at the rate at which fluid enters the wellbore from the formation. In the intermittent flow system, fluid is allowed to accumulate and build up in the tubing at the

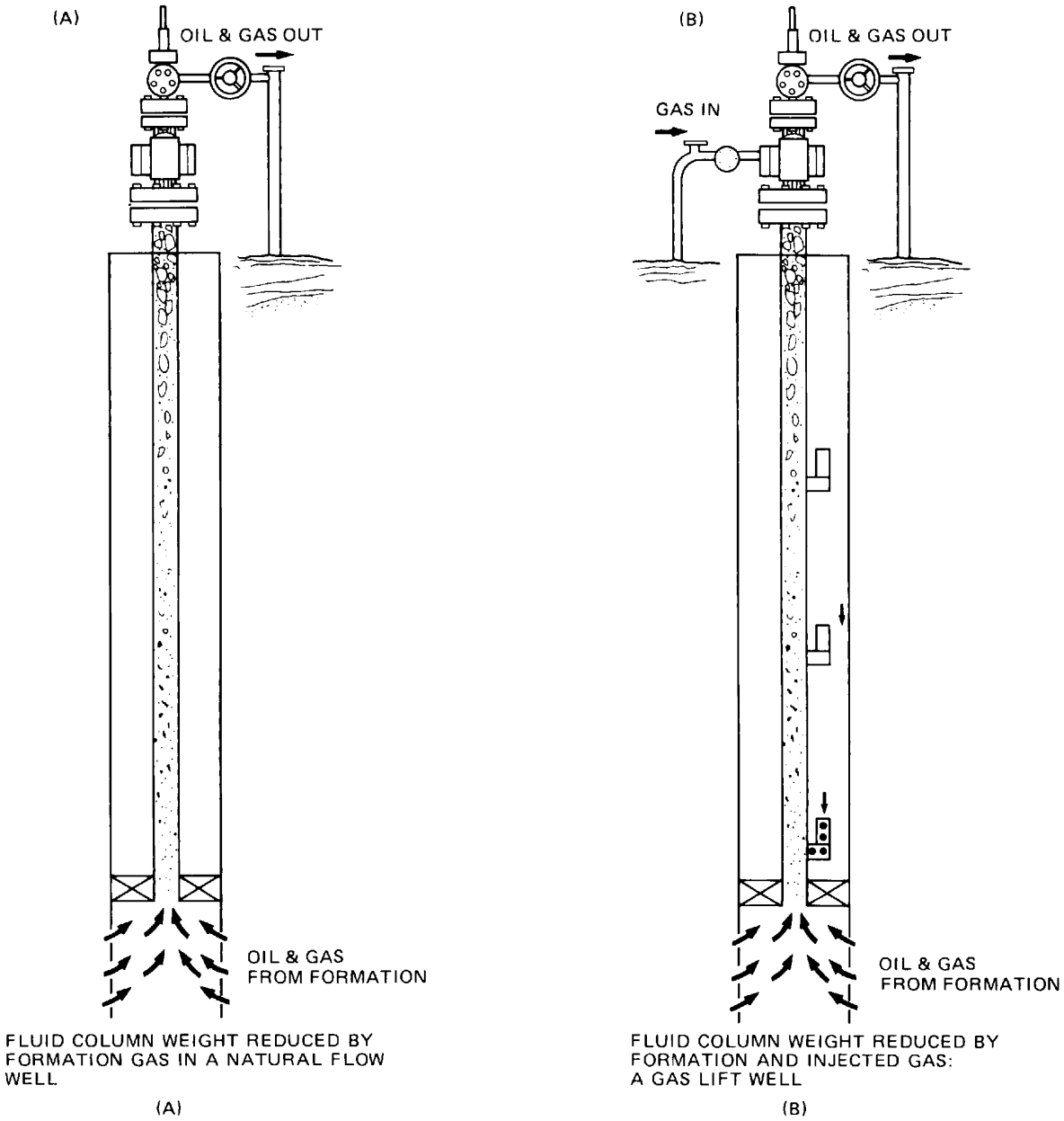


Fig. 1-3 — Reduction in fluid column weight by formation and injected gas

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bottom of the well. Periodically, a large bubble of high pressure gas is injected into the tubing very quickly underneath the column of liquid and the liquid column is pushed rapidly up the tubing to the surface. This action is similar to firing a bullet from a rifle by the expansion of gas behind the rifle slug. The frequency of gas injection in intermittent lift is determined by the amount of time required for a liquid slug to enter the tubing. The length of the gas injection period will depend upon the time required to push one slug of liquid to the surface.

ADVANTAGES AND LIMITATIONS OF GAS LIFT

Choice of Gas Lift System

Because of its cyclic nature, intermittent flow gas lift is suited only to wells that produce at relatively low rates. Continuous flow gas lift will usually be more efficient and less expensive for wells that produce at higher rates where continuous flow can be maintained without excessive use of injection gas.

Gas lift is suitable for almost every type of well that requires artificial lift. It can be used to artificially lift oil wells to depletion, regardless of the ultimate producing rate; to kick off wells that will flow naturally; to back flow water injection wells; and to unload water from gas wells.

The advantages of gas lift can be summarized as follows:

1. Initial cost of downhole gas lift equipment is usually low.
2. Flexibility cannot be equaled by any other form of lift. Installations can be designed for lifting initially from near the surface and for lifting from near total depth at depletion. Gas lift installations can be designed to lift from one to many thousands of barrels per day.
3. The producing rate can be controlled at the surface.
4. Sand in the produced fluid does not affect gas lift equipment in most installations.

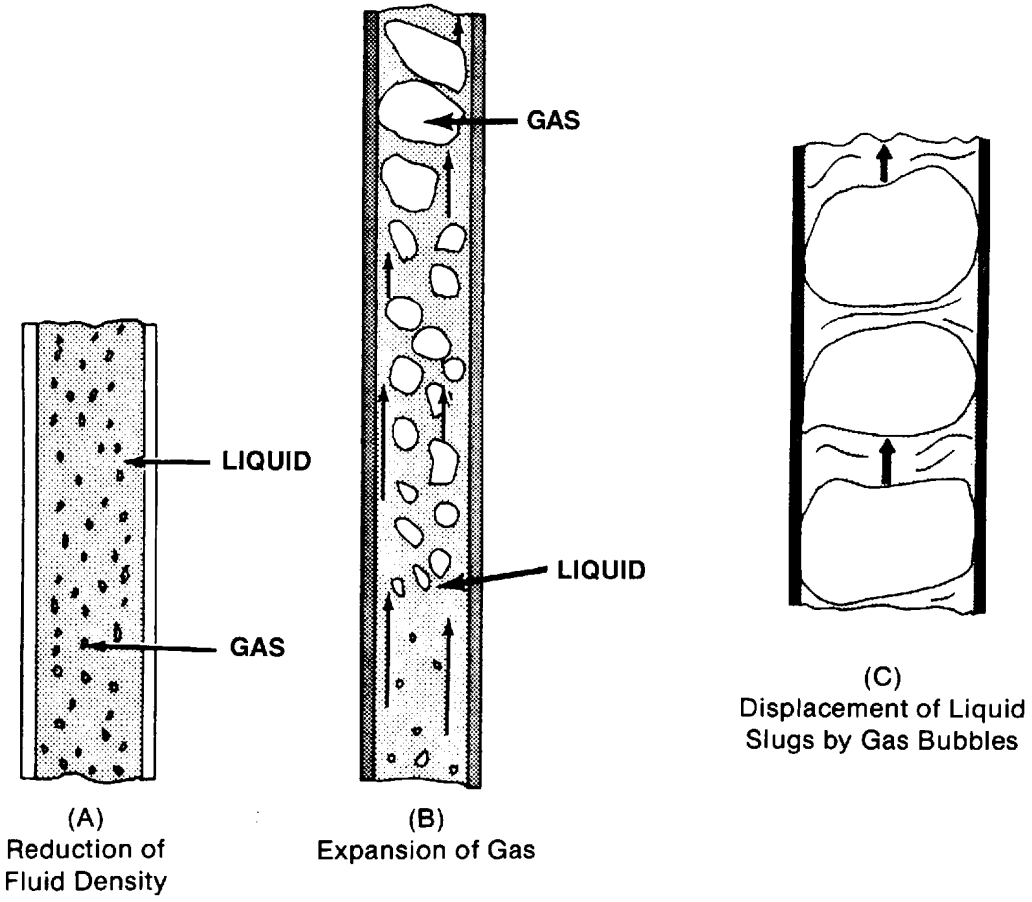


Fig. 1-4 — Three effects of gas in a gas lift well

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5. Gas lift is not adversely affected by deviation of the wellbore.
6. The relatively few moving parts in a gas lift system give it a long service life when compared to other forms of artificial lift.
7. Operating costs are usually relatively low for gas lift systems.
8. Gas lift is ideally suited to supplement formation gas for the purpose of artificially lifting wells where moderate amounts of gas are present in the produced fluid.
9. The major item of equipment (the gas compressor) in a gas lift system is installed on the surface where it can be easily inspected, repaired and maintained. This equipment can be driven by either gas or electricity.

On the other hand, gas lift also has certain limitations which can be summarized as follows:

1. Gas must be available. In some instances air, exhaust gases, and nitrogen have been used but these are generally more expensive and more difficult to work with than locally produced natural gas.
2. Wide well spacing may limit the use of a centrally located source of high pressure gas. This limitation has been circumvented on some wells through the use of gas-cap gas as a lifting source and the return of the gas to the cap through injection wells.
3. Corrosive gas lift gas can increase the cost of gas lift operations if it is necessary to treat or dry the gas before use.

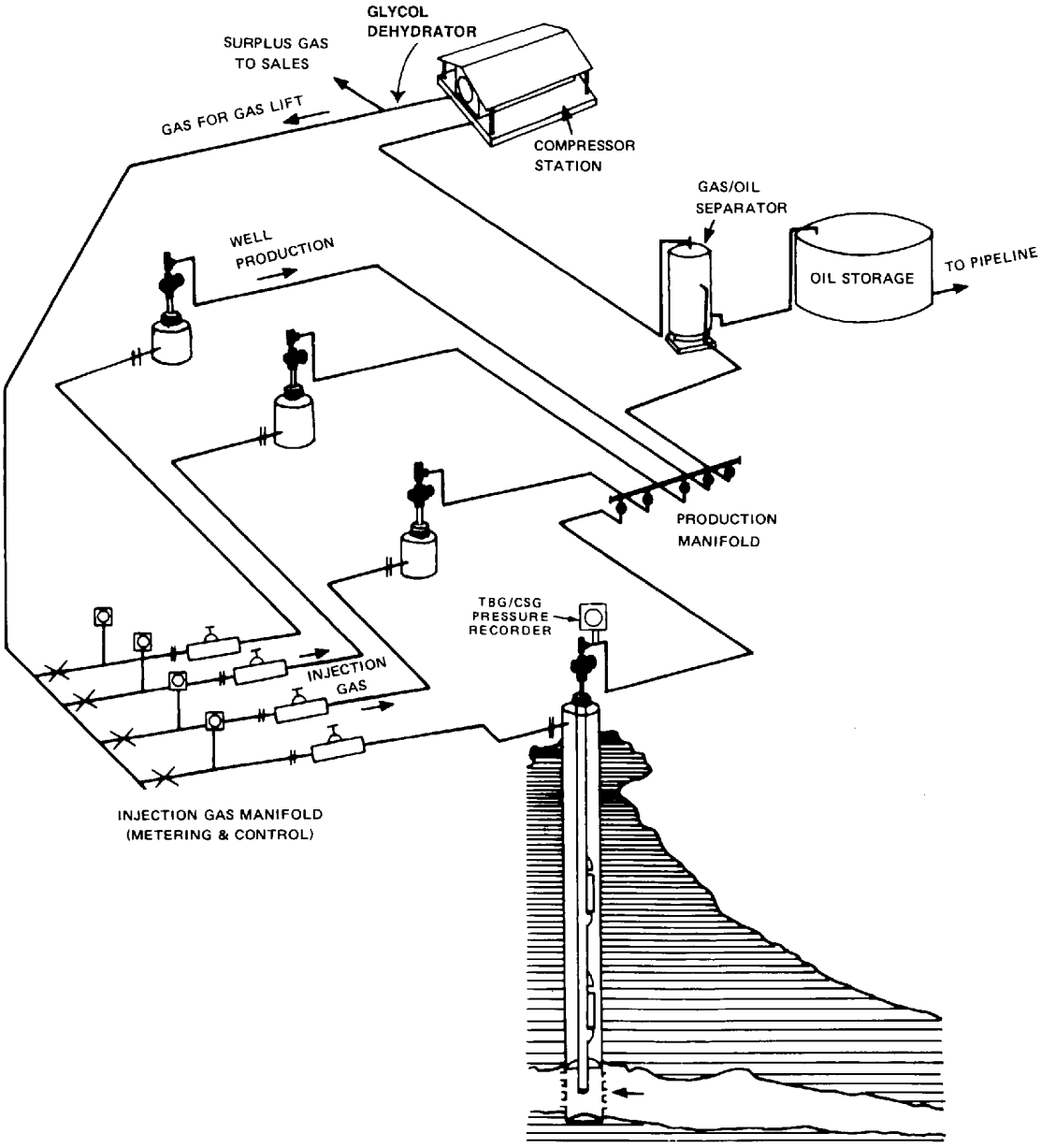


Fig. 1-5 — A typical gas lift system

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4. Installation of a gas lift system including compressors usually requires a longer lead time and greater preparation than does single well pumping systems. In addition, the initial surface installation for gas lift will sometimes be more expensive than equivalent pumping installations. However, the reduced operating cost of the gas lift system will usually far out weigh any additional cost of the initial installation. Also, if the associated gas will be gathered and compressed, as is usually the case, provisions for circulating some of the compressed gas for gas lift will not, in most cases, significantly increase the initial cost.

5. In very low pressured reservoirs, continuous flow gas lift cannot achieve as great a pressure drawdown as can some pumping systems. However, when low flowing bottomhole pressure is desired, the use of intermittent lift and chamber lift forms of gas lift can usually achieve pressure draw downs comparable to pumping systems.

6. Conversion of old wells to gas lift can require a higher level of casing integrity than would be required for pumping systems.

HISTORICAL REVIEW OF GAS LIFT DEVELOPMENT

Early Experiments

Carl Emanual Loscher (German mining engineer) applied compressed air as a means of lifting liquid in laboratory experiments in 1797. The first practical application of air lift was in 1846 when an American named Cockford lifted oil from some wells in Pennsylvania.

The first U.S. patent for gas lift called an "oil ejector" was issued to A. Brear in 1865 (Fig. 1-6).

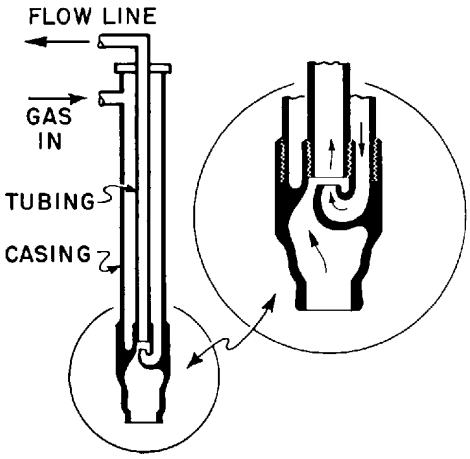


Fig. 1-6 — Brear Oil Ejector (May 23, 1865)

Chronological Development

The following chronological development of gas lift was given by Brown, Canalizo and Robertson in a paper published in 1961. (Many of the sketches shown in this chapter are taken from this paper.)

1. Prior to 1864: Some laboratory experiments performed with possibly one or two practical applications.
2. 1864-1900: This era consisted of lifting by compressed air injected through the annulus or tubing. Several flooded mine shafts were unloaded. Numerous patents were issued for foot-pieces, etc.
3. 1900-1920: Gulf Coast Area "air for hire" boom. Such famous fields as Spindle Top were produced by air lift.
4. 1920-1929: Application of straight gas lift with wide publicity from the Seminole Field in Oklahoma (See Fig. 1-7).

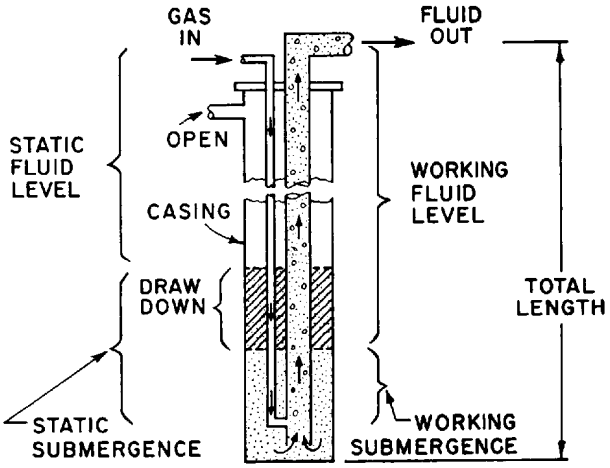


Fig. 1-7 — Early gas lift nomenclature

5. 1929-1945: This era included the patenting of about 25,000 different flow valves. More efficient rates of production as well as proration caused the development of the flow valve.
6. 1945 to present: Since the end of World War II, the pressure-operated valve has practically replaced all other types of gas lift valves. Also in this era, many additional companies have been formed with most of them marketing some version of a pressure-operated valve.
7. 1957: Introduction of wireline retrievable gas lift valves.

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Technical Development of Gas Lift Equipment

The technical development of gas lift equipment can be grouped into stages which are described as follows:

1. Straight gas injection which employed no valves and consisted primarily of U-tubing the gas around the bottom of the tubing. Several types of early gas and air lift hookups are shown in Fig. 1-8.

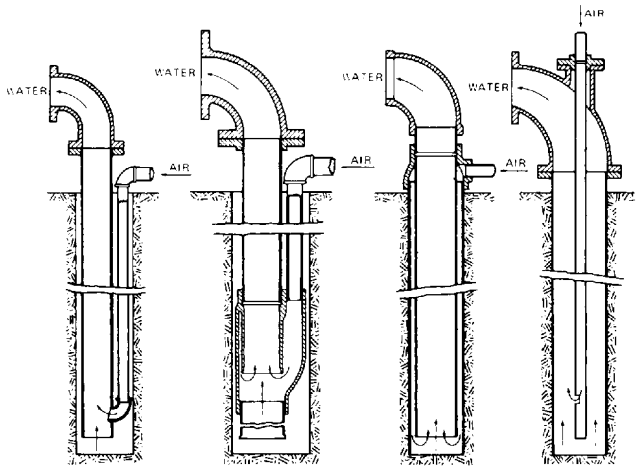


Fig. 1-8 — Early gas (air) lift without valves

2. Jet collars (Fig. 1-9) were placed up the string to allow gas to enter higher up and thereby reduce the excessive kick-off pressures required for kicking around the bottom.

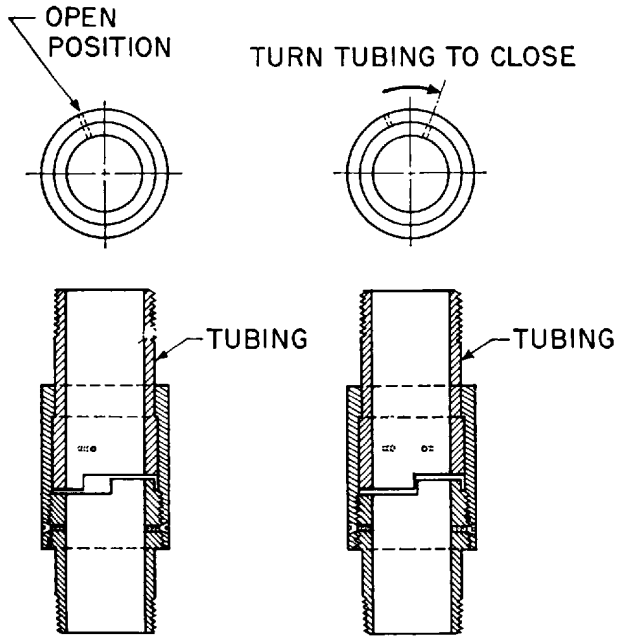


Fig. 1-9 — Jet collar

3. Kick-off valves (Fig. 1-10 and Fig. 1-11) were next employed to provide a means for closing off gas after a lower valve was uncovered. The early kick-off valves were designed to operate on a 10-20 psi pressure differential until the development of the spring-loaded differential valve which operated at about 100 psi differential. The kick-off valve was a crude forerunner of the modern gas lift flow valve.

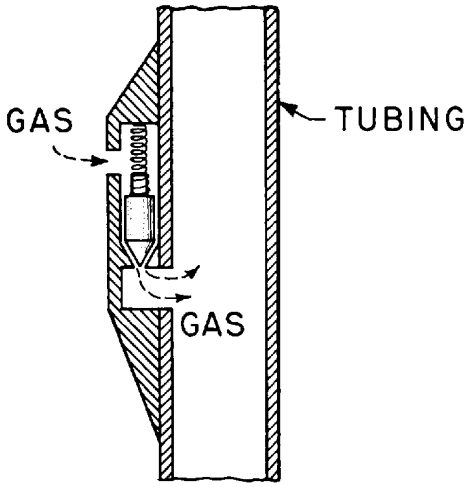


Fig. 1-10 — Taylor kick-off valve

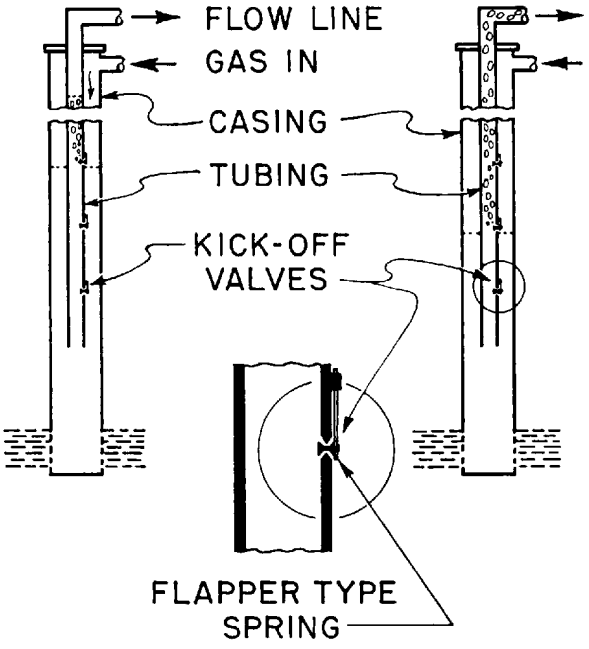


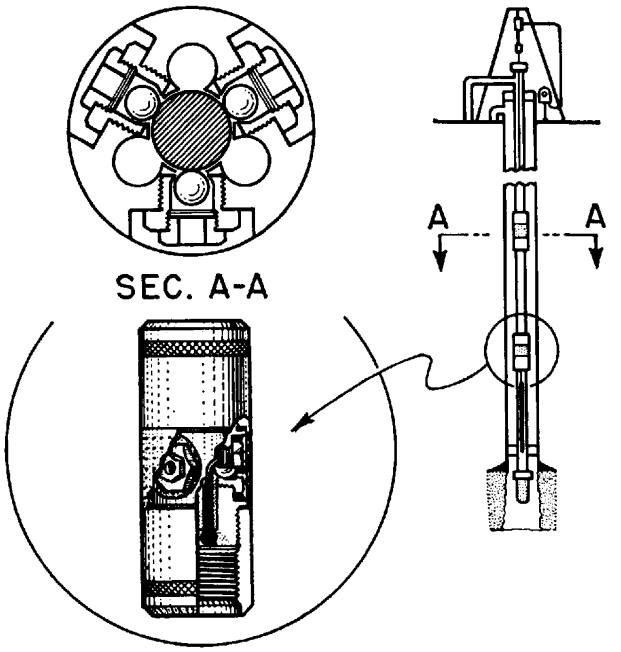
Fig. 1-11 — Kick-off valves

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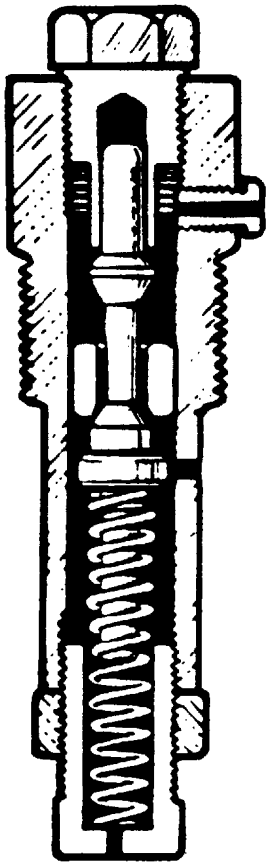
DEVELOPMENT OF THE MODERN GAS LIFT VALVE

Differential Valves

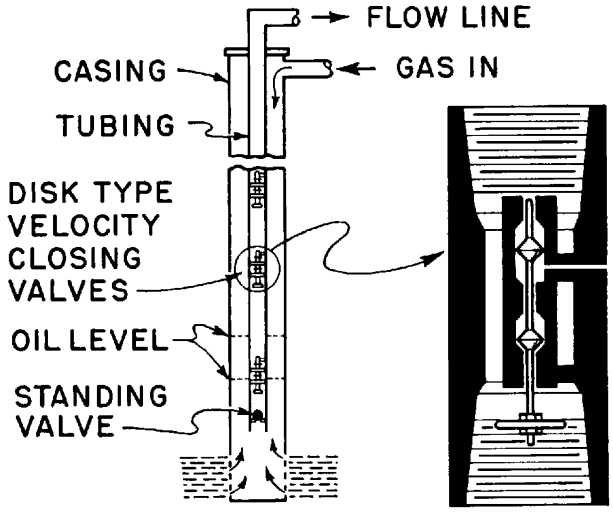
Until 1940, the closest thing to the present day gas lift flow valve was the differential valve (Fig. 1-12) which was operated by the difference in pressure between the injection gas in the casing and the fluid in the tubing. The differential valve opened when there was an increase in fluid pressure relative to injection gas pressure and closed when the gas pressure increased relative to the fluid. This principle of operation meant that the differential valves had to be spaced close together in order to assure proper operation of the installation. Little or no surface control was possible in a differential valve installation.



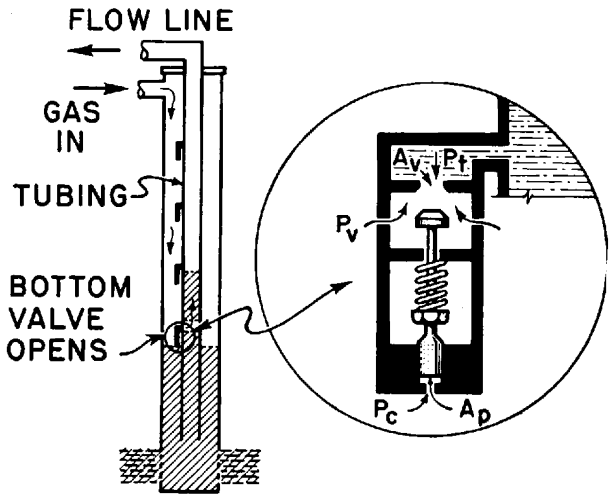
(A) Mechanically controlled valves



(B) Bryan differential valve



(C) Velocity controlled valves



(D) Spring loaded differential valves

Fig. 1-12 — Early types of flow valves

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One type of differential valve, which was very popular around 1940, is shown in Fig. 1-13. This valve was originally called the *Specific Gravity Differential Valve*. The specific gravity differential valve employed the difference in specific gravity between a 16 foot column of kerosene and a 16 foot column of well fluid for operating pressure. It was very successful in continuous flow wells and may still be operating successfully in some wells. However, the valve's length and excessive diameter limited its transportability and application.

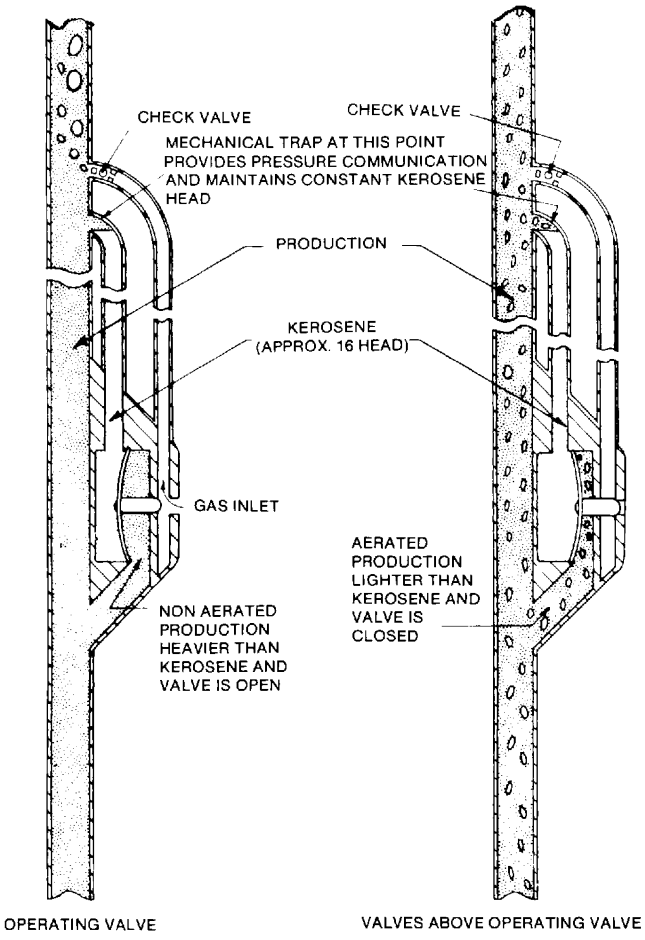


Fig. 1-13 — Specific gravity type differential valve

Bellows Charged Valves

In 1940, W. R. King introduced his bellows charged gas lift valve. A drawing taken from King's patent issued on January 18, 1944 is shown in Fig. 1-14. King's valve, which is very similar to most present day unbalanced, single-element, bellows charged gas lift valves, allowed for the first time the gas lifting of low pressure wells with a controlled change in the surface injection gas pressure. Since King's valve was opened by an increase in injection gas pressure

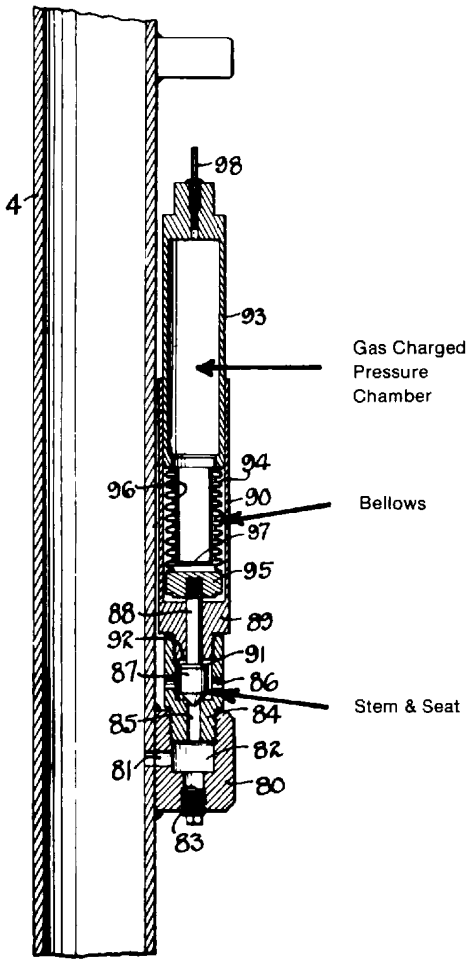


Fig. 1-14 — King valve (First pressured bellows valve)

and closed by a decrease in pressure, the valve could be operated from the surface by changes in the injection gas pressure. This meant that it was no longer necessary to operate a valve from the surface by rotating or moving the tubing or wireline connected to the surface. The principal of operation of the bellows valve was also far superior to the differential valve for most applications in that the bellows valve was closed by a decrease in gas pressure, whereas the differential type valve opened with a decrease in gas pressure. This meant that fewer of the bellows type gas pressure operated valves were required for each installation, since the valve relied on the relatively high injection gas pressure for operation, thereby allowing the spacing between valves to be much greater than the differential pressure operated valves.

King had good insight into valve construction when he designed his valve. He recognized the need for complete bellows protection, including an anti chatter mechanism. The bellows in the King valve is protected from excessive well pressure by sealing the bellows chamber from the well fluids after full stem travel. Chatter is prevented by the

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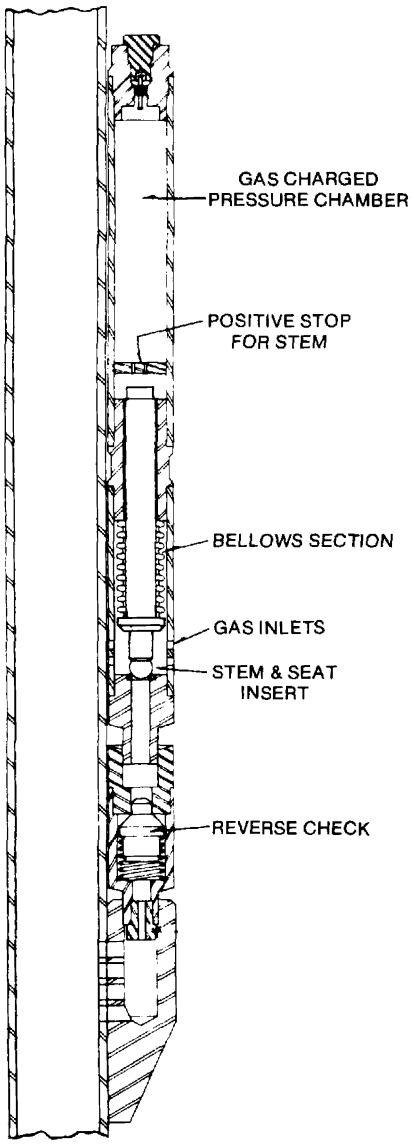


Fig. 1-15 — Typical modern bellows charged gas lift valve

small orifice. The baffle design also supports the bellows. Similar construction is used by several manufacturers in their present gas lift valves.

The success of the King valve is evidenced by the fact that the basic principles used in the design were quickly adopted by almost all valve manufacturers and are still used with little modification in today's gas lift valves. Fig. 1-15 is an illustration of a typical modern bellows charged gas lift valve. Note the similarity between this valve and the King valve shown in Fig. 1-14. Gas lift valves and mandrels are discussed in detail in Chapter 5 of this manual.

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CHAPTER 2
WELL PERFORMANCE

INTRODUCTION

Well performance is controlled by a large number of factors that are often interrelated. Most students of fluid flow now divide well performance into two basic categories which they call Inflow and Outflow performance. As illustrated in Fig. 2-1, all flow in the reservoir up to the wellbore is designated as *inflow performance* and all flow up the tubing and into the production facilities is designated *outflow performance.*

A well's *inflow performance* is controlled by the characteristics of the reservoir such as reservoir pressure, productivity and fluid composition. A well's *outflow performance* is a direct function of the size and type of producing equipment. Both inflow and outflow performance can be predicted quite accurately, and wells can be designed based on these predictions. In any given well, outflow performance and inflow performance must be equal. That is, we can produce no more fluid from the reservoir than we can lift to the surface and vice versa. Because of this fact, it is extremely important that a well's inflow performance be carefully considered when sizing production equipment.

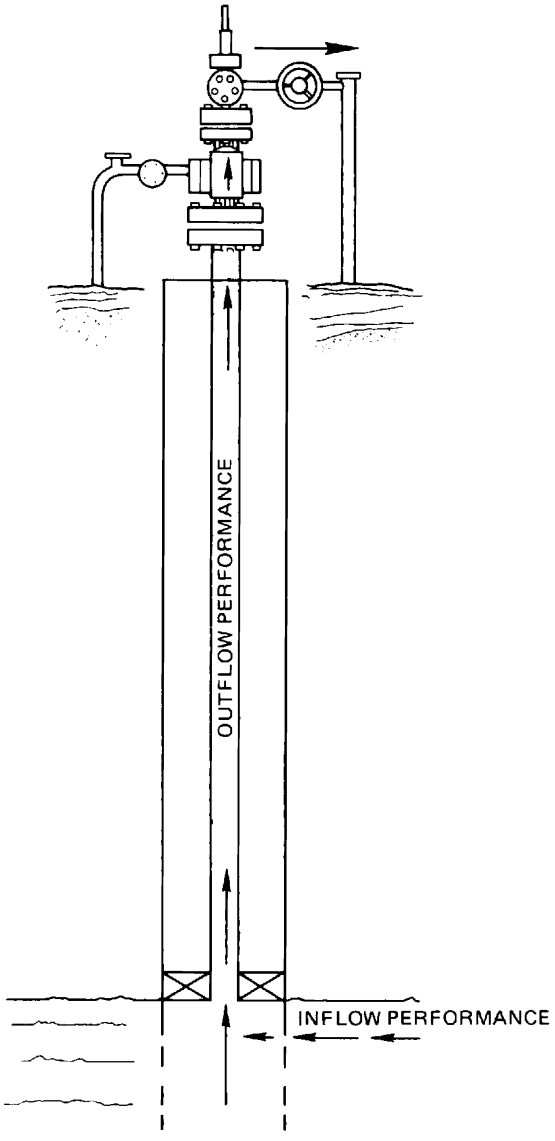


Fig. 2-1 — Inflow and Outflow Performance in a flowing well

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INFLOW PERFORMANCE PREDICTION

A well's inflow performance is usually expressed in terms of productivity which simply indicates the number of barrels of oil or liquid that a well is capable of producing at a given reservoir pressure. One way of expressing well productivity is with the Productivity Index (P.I.=J) technique. This involves measuring a well's producing rate, and flowing bottomhole pressure at that rate, then using this information to calculate a P.I for the well.

Productivity Index (P.I.=J) Technique

One definition of Productivity Index and the one that is used in artificial lift, defines P.I. as the number of barrels of liquid produced per day (BLPD) for each pound per square inch (psi) of reservoir pressure drawdown. Drawdown is defined as the difference in the stabilized static bottomhole pressure (SSBHP) and the flowing bottomhole pressure (FBHP). This can be written as an equation using current engineering symbols as follows:

$$J = \frac{q_l}{P_{ws} - P_{wf}} \qquad \text{Equation 2.1}$$

where: J = Productivity index, BLPD/psi
q_l = Liquid Production Rate, BLPD
P_{ws} = Static bottomhole pressure, psig
P_{wf} = Flowing bottomhole pressure, psig

The calculation of a well's P.I. is given in the following example.

Given: A well that produces 100 BLPD and has an SSBHP of 1000 psig and a FBHP of 900 psig.

Find: P.I. of the well

Solution:

$$J = \frac{q_l}{P_{ws} - P_{wf}} = \frac{100 \text{ BLPD}}{1000 \text{ psig} - 900 \text{ psig}}$$

J = 1 BLPD/psi Equation 2.1

The P.I. technique allows us to determine the well production if the pressure is drawn down further. Using the same example, if we draw the FBHP down to 500 psig from the SSBHP of 1000 psig the well should produce at the following rate:

$$J = \frac{q_l}{P_{ws} - P_{wf}} \qquad \text{Equation 2.1}$$

or rearranging the equation:

$q_l = (J) \times (P_{ws} - P_{wf}) = 1 \times 500$
Rate (q_l) = 500 BLPD at FBHP (P_{wf}) of 500 psig

Inflow Performance Relationship (IPR) Technique

The P.I. method assumes that all future production rate changes will be in the same proportion to the pressure drawdown as was the test case. This may not always be true, especially in a solution-gas drive reservoir producing below the bubble point pressure. The bubble point pressure is the condition of temperature and pressure where free gas first comes out of solution in the oil. When the pressure in the formation drops below the bubble point pressure, gas is released in the reservoir and the resulting two-phase flow of gas and oil around the wellbore can cause a reduction in the well's productivity. J. V. Vogel developed an empirical technique for predicting well productivity's under such reduced conditions and he called his method of analysis Inflow Performance Relationship (IPR) after the terminology used in an earlier paper written by W. E. Gilbert.[1]

Vogel[2] calculated IPR curves for wells producing from several fictitious solution gas drive reservoirs. From these curves he was able to develop a reference IPR curve which not only could be used for most solution gas drive reservoirs in arriving at oil well productivity, but would give much more accurate projections than could be obtained using the P.I. method. His work was based entirely upon results obtained from wells producing in solution gas drive reservoirs. However, good experience has been obtained using the Vogel IPR in all two-phase flow conditions.

Vogel IPR Curve

The Vogel IPR dimensionless curve (see Fig. 2-2) is based on the following equation:

$$\frac{q_0}{(q_0)_{max}} = 1.0 - 0.2\left(\frac{P_{wf}}{P_B}\right) - 0.8\left(\frac{P_{wf}}{P_B}\right)^2 \qquad \text{Equation 2.2}$$

Note that the initial bubble point pressure (P_B) has been substituted for the static bottomhole pressure (P_{ws}) in the above equation to emphasize that the Vogel IPR curve only applies when $P_{wf} = P_B$ The change in production with a change in the flowing bottomhole pressure above the initial bubble point reservoir pressure is defined by the productivity index equation, which is a straight line IPR curve. The second requirement to assure validity of the Vogel IPR relationship is that the flow efficiency (FE) must be equal to unity (FE = 1.0) where flow efficiency is defined as the ratio of the actual to the ideal productivity index. Ideal implies no skin effect; that is, the absolute permeability and porosity of the formation remain in the same and unaltered from the drainage radius to the wellbore radius.

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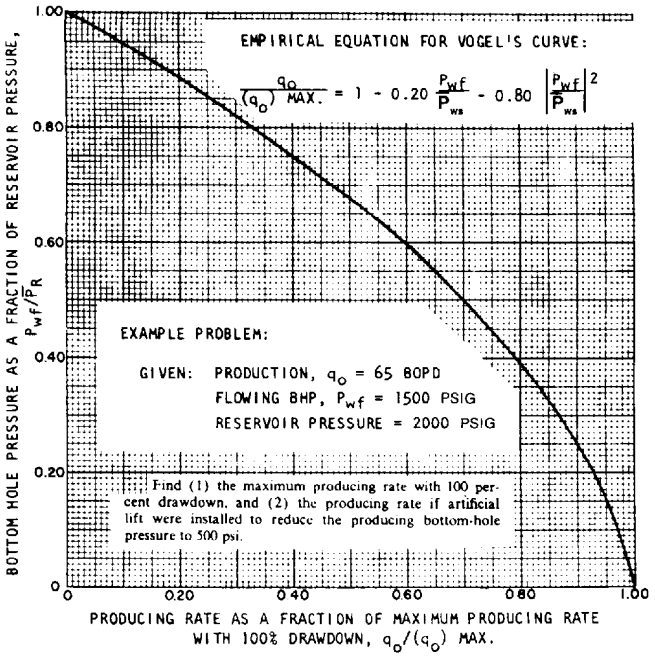


Fig. 2-2 — Vogel's curve for inflow performance relationship (from Vogel's paper, SPE 1476)

Since this discussion is an introduction to the application of the widely-used Vogel IPR curve and not a detailed presentation on the concepts of well damage and inflow performance, the example calculations will be based on the assumptions that $P_{ws} = P_B$ and FE 1.0. Also, the IPR curve will not be restricted to all oil production if free gas is present with the liquid phase at the flowing bottomhole pressures in the wellbore. If a well produces free gas, and a significant flowing bottomhole drawdown below the initial bubble point pressure is required for the desired daily production rate, more accurate production predictions can be expected using the Vogel IPR curve than using a straight line productivity index relationship for water-cut wells. The incremental increase in production for the same incremental increase in flowing bottomhole pressure drawdown becomes less at the lower flowing bottomhole pressure. Gage pressures will be used in these calculations. A worksheet for performing IPR calculations is given in Fig. 2-3.

Vogel's Example Problem

The following data for illustrating IPR calculations were used in Vogel's paper:

Given: 1. Average reservoir pressure, P_{ws} = 2000 psig ($P_{ws} = P_B$)
2. Daily production rate = q_o = 65 BOPD
3. Flowing bottomhole pressure, P_{wf} = 1500 psig

Find: 1. Maximum production rate for 100 percent drawdown (P_{wf} = 0 psig)
2. Daily production rate for a flowing bottomhole pressure equal to 500 psig
(See Figures 2-4 and 2-5 for a graphical presentation of the Solution.)

Solution:

1. The maximum production rate, (q_o) max, is calculated using the given test q_o and corresponding P_{wf}.

$$\text{Pressure Ratio} = \frac{P_{wf}}{P_{ws}} = \frac{1500}{2000} = 0.75$$

From the Vogel IPR curve: Rate Ratio, $\frac{q_o}{(q_o)_{max}} = 0.40$

$$(q_o)_{max} = \frac{q_o}{0.4} = \frac{65}{0.4} = 162.5 \text{ BOPD}$$

The maximum daily production rate represents the maximum deliverability of the well if the bottomhole pressure could be decreased to atmospheric pressure (0 psig) by turning the well upside down and producing through a frictionless conduit.

2. $$\text{Pressure Ratio} = \frac{P_{wf}}{P_{ws}} = \frac{500}{2000} = 0.25$$

From the Vogel IPR curve: Rate Ratio, $\frac{q_o}{(q_o)_{max}} = 0.90$

$q_o = 162.5\ (0.90) = 146$ BOPD

When the valve for $(q_o)_{max}$ is determined, the value of q_o for all values of P_{wf} can be calculated. Also, the value of P_{wf} can be calculated for any value of q_o less than $(q_o)_{max}$. As an example, the flowing bottomhole pressure for a production rate of 114 BOPD for the above well can be calculated as follows:

$$\text{Rate Ratio} = \frac{q_o}{(q_o)_{max}} = \frac{114}{162.5} = 0.70$$

From the Vogel IPR curve: Pressure Ratio, $\frac{P_{wf}}{P_{ws}} = 0.50$

$P_{wf} = 0.5\ (2000) = 1000$ psig

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WORK SHEET FOR
NONDIMENSIONAL INFLOW PERFORMANCE CURVE

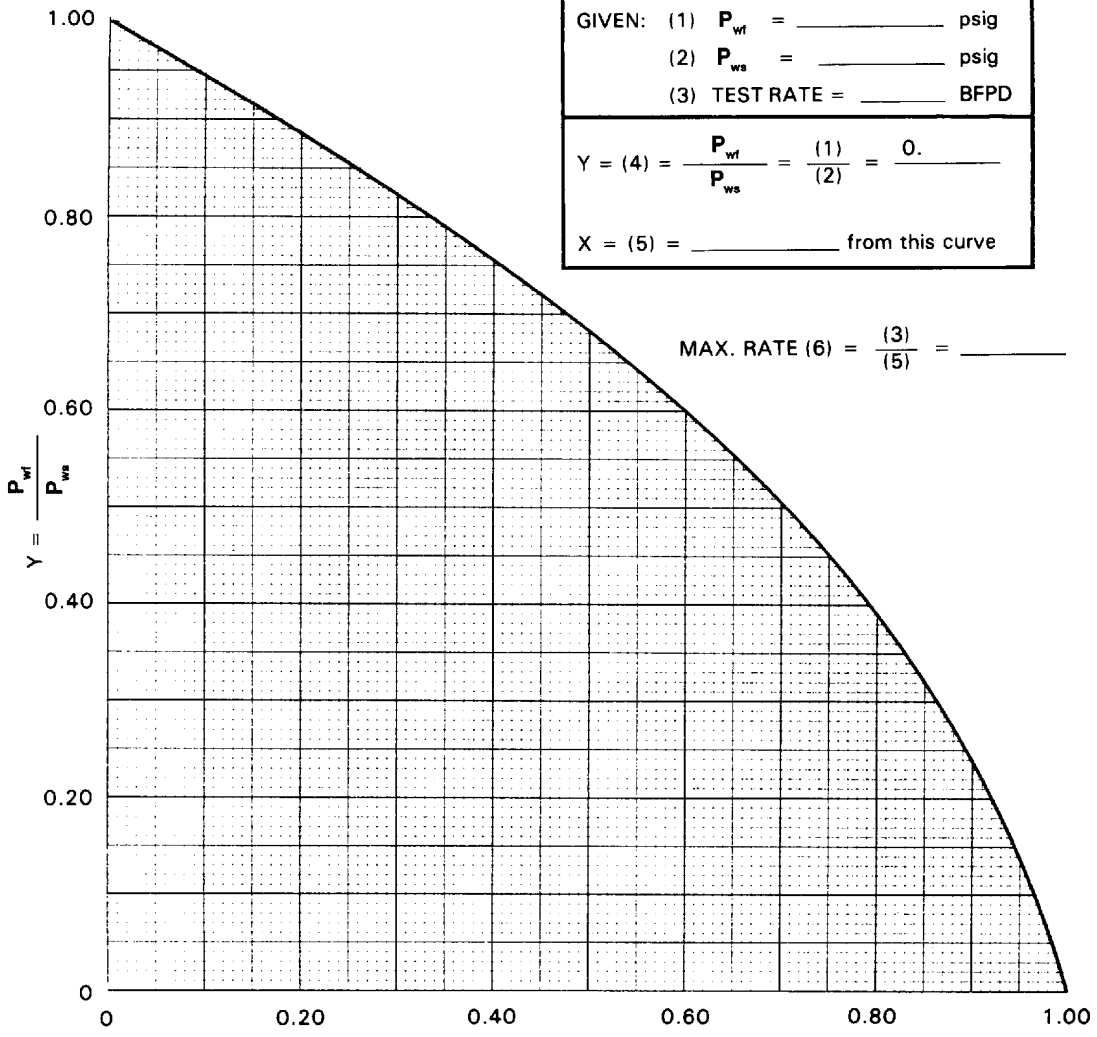
WELL NO. _____

FROM BHP SURVEY
GIVEN: (1) P_{wf} = _____ psig
(2) P_{ws} = _____ psig
(3) TEST RATE = _____ BFPD

$Y = (4) = \frac{P_{wf}}{P_{ws}} = \frac{(1)}{(2)} = \frac{0.}{\quad}$

X = (5) = _____ from this curve

MAX. RATE (6) = $\frac{(3)}{(5)}$ = _____



(4) × (2) = (7)	(5) × (6) = (8)
Y(4) times P_{ws} (2) = BHP (7)	X(5) times MAX. RATE (6) = BFPD(8)
1.0 × (2) _____ = _____	0 × (6) _____ = 0
.75 × (2) _____ = _____	.40 × (6) _____ = _____
.50 × (2) _____ = _____	.70 × (6) _____ = _____
.25 × (2) _____ = _____	.90 × (6) _____ = _____
0 × (2) _____ = 0	1.00 × (6) _____ = _____ = (6)

Plot BHP(7) versus BFPD(8) for IPR Curve between BHP = 0 & BHP = P_{ws} & BFPD = 0 & BFPD = Max. Rate (6)

Fig. 2-3 — Worksheet for performing IPR calculations

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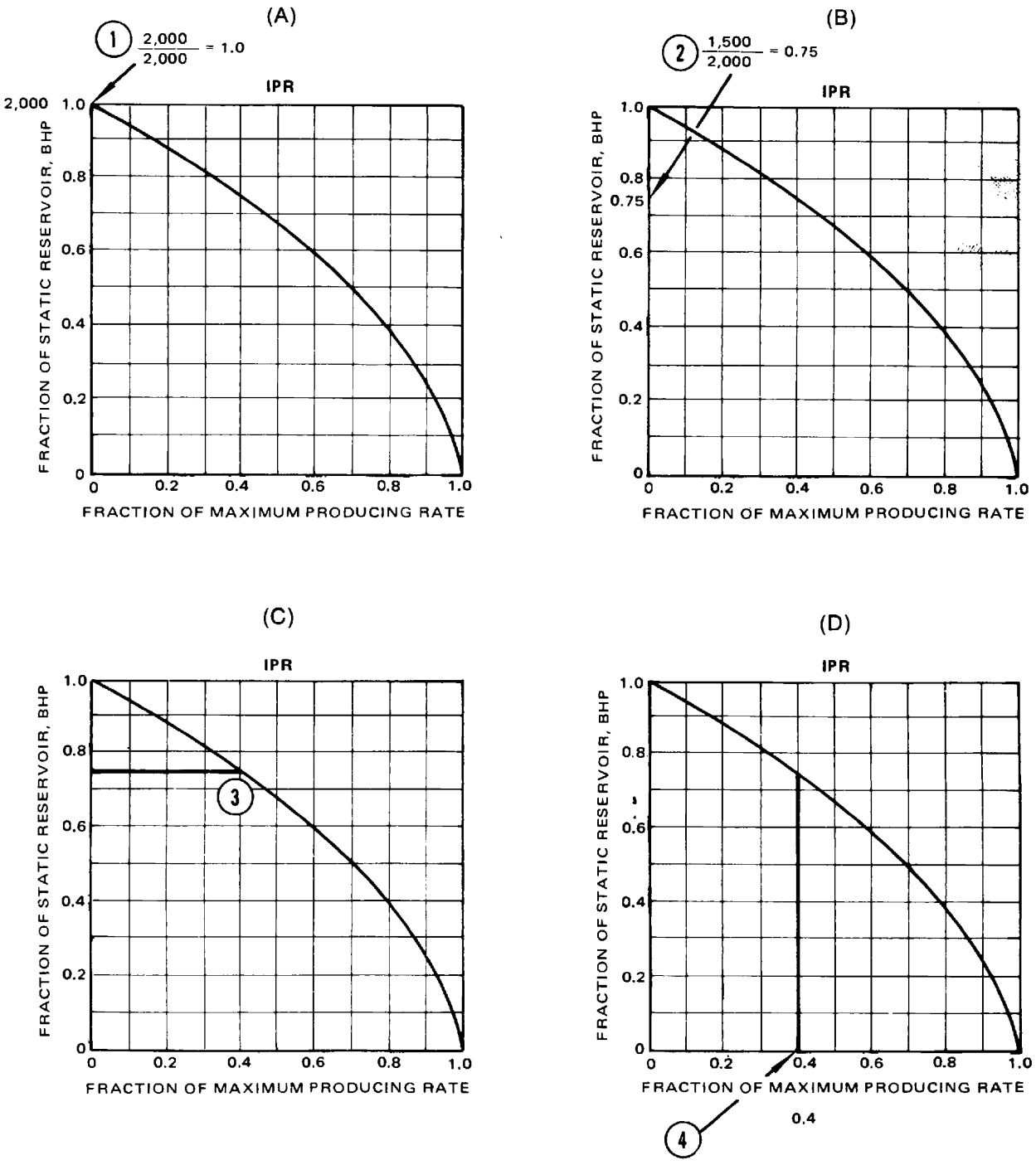


Fig. 2-4 — Example problem solution

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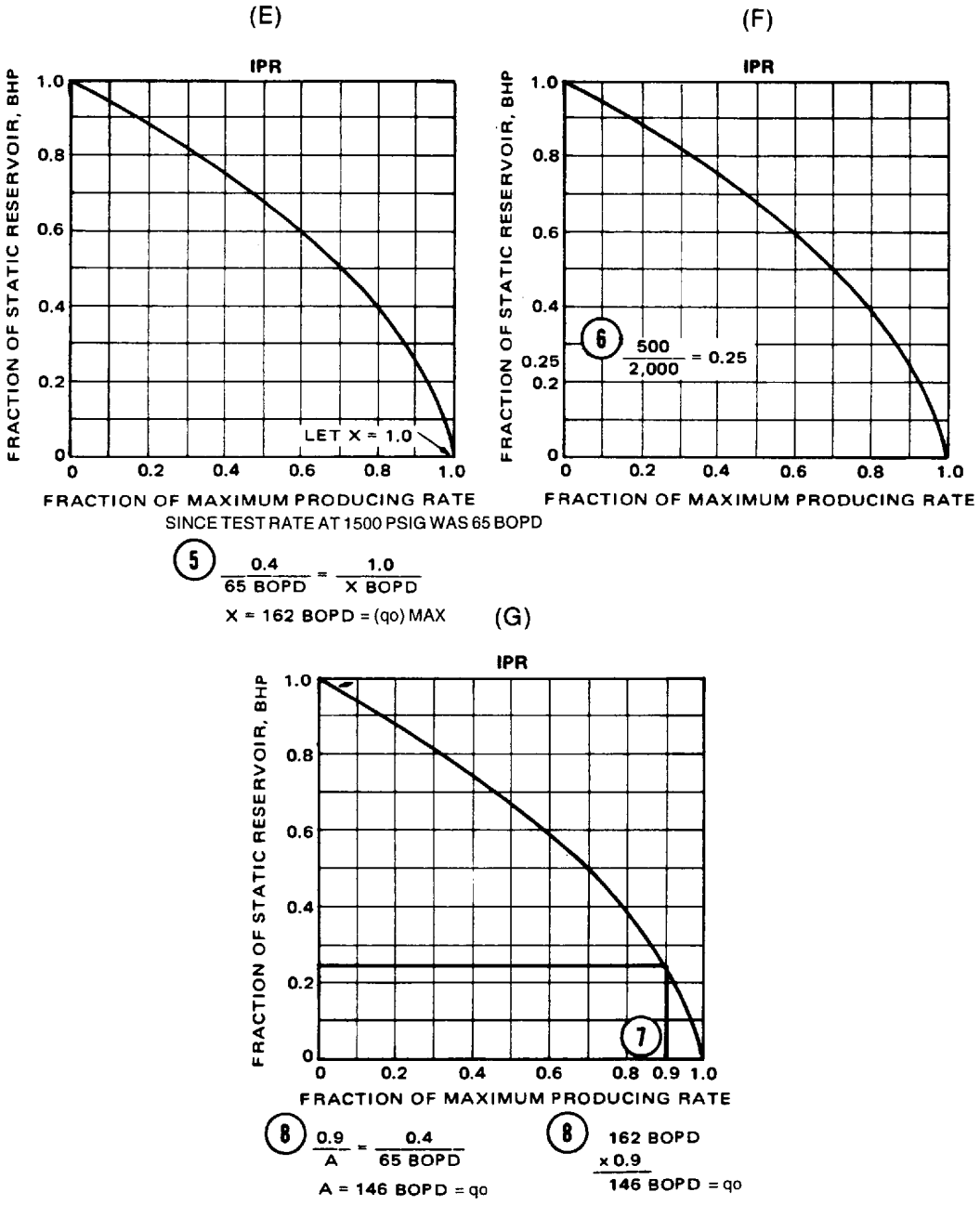


Fig. 2-5 — Continuation of example problem

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WELL OUTFLOW PERFORMANCE PREDICTION

Well outflow performance depends upon many complex factors which are often as difficult to simulate as those for inflow performance. Such varied parameters as fluid characteristics, well configuration, conduit size, wellhead back pressure, fluid velocity, and pipe roughness all contribute significantly to outflow performance.

Efforts to predict well outflow performance have been going on for many years and these efforts have culminated in much research and development work being done in the area of multiphase flow correlations. The flow correlations that have developed from this work attempt to predict the pressure at depth in a flowing vertical column of multiphase fluid (oil-gas, oil-water-gas, or water-gas) taking into account all of the fluid characteristics along with the conduit configuration and other factors affecting the flow. Since the producing characteristics of continuous flow gas lift wells are essentially the same as those for a naturally flowing well, the flow correlations that have been developed work equally well in either system. The development and use of multiphase flow correlations for outflow performance predictions are discussed in Chapter 3.

Example Problem

All of the correlations for predicting multiphase flow require extensive calculations and from a practical standpoint can only be done with a computer. Fortunately these computer calculations have been plotted into generalized pressure gradient curves that are immediately available to the operator and engineer. An example of one such gradient curve is shown in Fig. 2-6A. Using a suite of these gradient curves calculated for several different well rates, the flowing bottomhole pressure P_{wf} can be read at a given depth for a specific rate and gas to liquid ratio (R_{gl}). Separate curves must be used for each well rate, water cut and R_{gl}. Fortunately, many of the variables in two phase flow cause only a small change and can be generalized. The following example demonstrates the use of these curves to predict outflow performance and well performance. Well data for the example problem follows:

Casing	7-inch O.D. (outside diameter)
Tubing	$2^7/_8$ inch O.D.
Static BHP (Today)	1970 psig @ 5800 ft.
Flowing Wellhead Back Pressure	230 psig
Injection Gas Pressure	1500 psig @ Surf.
Water Cuts (Assumed)	0-25-50-75%
Pressure Gradient Curves	EPR Correlation (Orkiszewski)
Tubing Setting Depth	Near 5800 ft.
Formation Gas Oil Ratio	800 CF/B
Productivity Index	5.0 BFPD/psi Drawdown (Straight Line)
Formation Depth	5800 ft.

The well under consideration is a high productivity well. To begin the analysis it is assumed that for this well, and the given reservoir conditions, maximum flow rates can probably best be obtained under annular flow conditions. This may not be true, and the maximum rates for $2^7/_8$ inch tubing will be checked later.

1. The first step is to obtain or calculate a suite of vertical two-phase flowing pressure gradient curves for the conduit sizes to be examined based on producing conditions to be expected. Computer programs available from several sources make the calculation and plotting of such curves both fast and inexpensive. Generalized curves, available in many textbooks, can be used if they closely match the actual producing conditions. The gradient curves used in this example are not typical, generalized well gradient curves, but were calculated for these specific conditions.

   The suite of gradient curves should cover all ranges of flow rates that are possible for the particular conduit being considered. Six to ten rates should be sufficient, but the actual number will depend on the width of the producing range being considered. The rates should be fairly equally divided over the entire range to give somewhat equal distribution of points along the entire length of the curve.

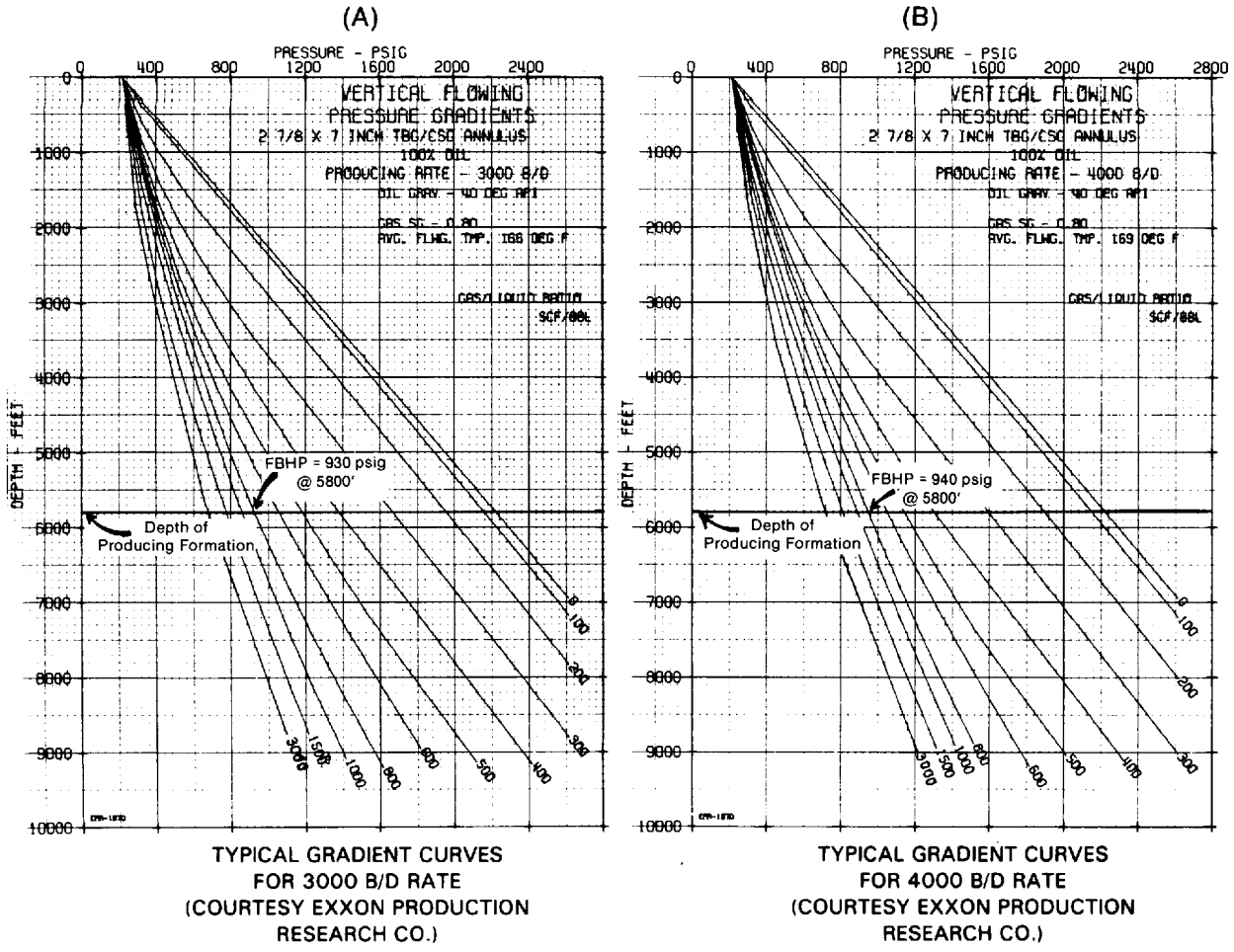
   A page of gradient curves calculated for this particular well and representing the 3000 BOPD rate is shown in Fig. 2-6A. In this case a line has been drawn representing the producing formation depth at 5800 ft. The intersection of the depth line with the R_{gl} line for natural flow conditions (800 R_{gl} for 100% oil) has been noted with an arrow. The pressure at this point has been read as 930 psig. Fig. 2-6B shows the gradient curves for the 4000 B/D fluid rate at 100% oil; and a similar reading, in this case 940 psig, has been noted on it. Gradient curve readings are con-tinued in this fashion until sufficient points are obtained to represent a full range of producing rates.

2. The pressure readings are now tabulated in the manner shown in Table 2-1. Note that the pressures shown in Table 2-1 are for both 100% oil and various water cuts. A separate suite of gradient curves is required for each water cut.

3. The points shown in Table 2-1 are now plotted on Cartesian Coordinate paper with flowing pressure at the formation depth being scaled along the vertical (Y) axis and the producing rate plotted along the horizontal (X) axis. Fig. 2-7 is a plot of these values and the resulting curves represent the minimum flowing pressure at the formation depth that will be required to overcome gravity, friction, surface pressure and other effects, and produce at the rates indicated.

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TYPICAL GRADIENT CURVES FOR 3000 B/D RATE (COURTESY EXXON PRODUCTION RESEARCH CO.)

TYPICAL GRADIENT CURVES FOR 4000 B/D RATE (COURTESY EXXON PRODUCTION RESEARCH CO.)

Fig. 2-6 — Gradient curves

TABLE 2-1
TABULATION OF POINTS FROM GRADIENT CURVE FOR NATURAL FLOW
7" x 2⅞" Annulus — Natural Flow — R_{gl} as Indicated

	FBHP @ 5800 ft, psig			
Rate, BPD	100% Oil (R_{gl} = 800)	25% Wtr (R_{gl} = 600)	50% Wtr (R_{gl} = 400)	75% Wtr (R_{gl} = 200)
2,000	990	1260	1655	2240
2,500	940	1180	1535	2190
3,000	930	1130	1465	2140
3,500	935	1110	1420	2100
4,000	940	1120	1390	2060
4,500	960	1120	1375	2020
5,000	970	1135	1370	2000
6,000	1000	1160	1370	1960
8,000	1080	1240	1440	1980
10,000	1180	1320	1500	2000
12,500	1320	1440	1600	2080

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4. On the same sheet of graph paper, plot the well productivity line based on either the straight line productivity index or the IPR technique by beginning at a point representing the static bottomhole pressure (SBHP) on the vertical axis. This example uses the straight line P.I. method. An example using the IPR curves is given in Fig. 2-13. In this case, the point is 1970 psig at 5800 ft. Continue the plot of the productivity line by reducing the flowing bottomhole pressure by the amount of drawdown calculated for various rates. For example, at a rate of 5000 B/D and with a P.I. of 5.0 BFPD psi, the drawdown from the static pressure of 1970 psig is 1000 psig. Therefore, the point to be plotted for the extension of the productivity line is 1970 psig less 1000 psig or 970 psig and is plotted opposite the 5000 BFPD rate.

5. The points of intersection of the drawdown line with the flowing pressure curves represent the maximum producing rate by natural flow which is possible under the given reservoir and well conditions if flow is up the $2^7/_8$" x 7" annulus. In this example, shown in Fig. 2-7, the maximum rate indicated is 5000 B/D at zero water cut and 4250 B/D at a 25% water cut. Note that the drawdown line does not intersect the 50% and 75% waters curves. This indicates that the natural flow is impossible regardless of rate where the water cut is 50% or more. Natural Flow then would cease on this well when it reaches a water cut somewhere between 25% and 50%.

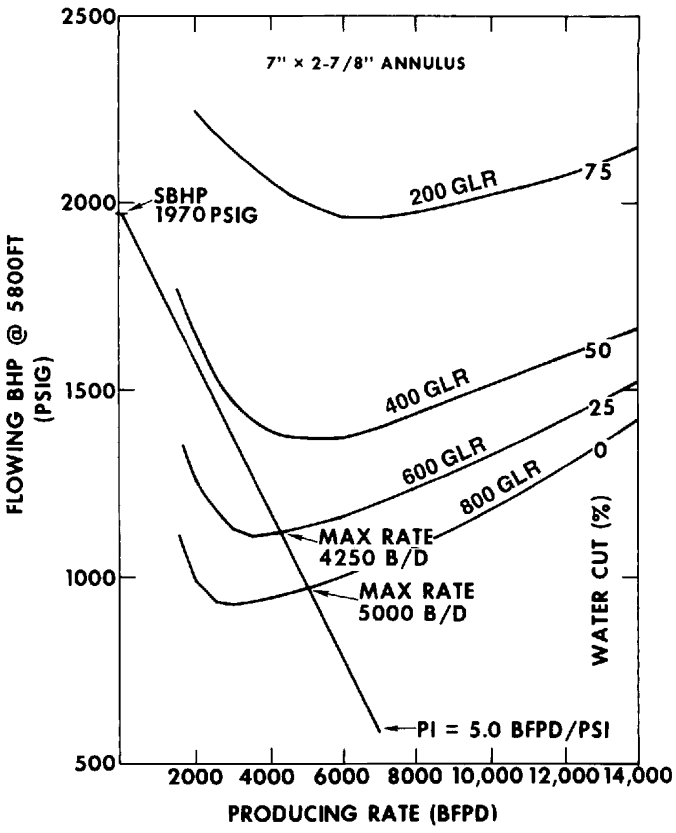


Fig. 2-7 — Flowing BHP vs. producing rate for natural flow conditions, various water cuts

PREDICTING THE EFFECT OF GAS LIFT

The effect of injecting additional gas into a fluid column from an outside source for gas lift purposes can be determined in the following manner.

1. Using the same gradient curves and the same method as for natural flow, determine the flowing pressure at the formation depth for the total gas liquid ratio (formation gas + injected gas). If there is no limit on the amount of gas that can be injected, the R_{gl} which produces the minimum gradient line at each producing rate can be used. In the example problem, that is a R_{gl} of 3000 at the 3000 B/D rate. Since this minimum gradient will represent different R_{gl} values at different rates, the calculation of injection gas requirement will depend on the minimum gradient for the rate being considered. Table 2-2 shows a tabulation of the minimum downhole pressure readings at the various rates.

2. Plot the pressures versus rates tabulated in Table 2-2 on Cartesian Coordinate paper in the same manner as in the example for natural flow. Fig. 2-8 shows a curve plotted for the maximum gas injection rate alongside the curve plotted for natural flow (800 R_{gl}) for the 100% oil case. A dotted line is also shown on Fig. 2-8 to indicate the 1200 R_{gl} curve which represents a plot of the flowing pressure for a case where injected gas is limited to 400 cubic feet per barrel (CF/B)(1200 - 800).

3. The maximum producing rates which are possible under various conditions are indicated by the intersection of the productivity line with the flowing pressure versus rate curves. In this case the maximum rate for unlimited gas lift is 5600 B/D, and for limited gas lift (400 CF/B injected gas) is 5450 B/D. These compare to a maximum natural flow rate under the same conditions of 5000 B/D. A comparison of maximum producing rates possible under both gas lift and natural flow conditions is shown in Table 2-3.

4. Using the above example, it is now possible to evaluate the benefits accruing to gas lift under the given conditions. Also, it is possible to determine the optimum gas injection rate by comparing the oil produced

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TABLE 2-2
TABULATION OF POINTS READ ON GRADIENT CURVES FOR GAS LIFT
7" x 2⅞" Annulus — Maximum Gas Lift — R_{gl} Values

Rate, B/D	FBHP @ 5800 ft, psig			
	100% Oil	25% Wtr	50% Wtr	75% Wtr
2,000	690	740	800	1400
2,500	680	740	800	1440
3,000	680	750	815	1470
3,500	700	760	840	1520
4,000	720	790	910	1540
4,500	750	860	940	1570
5,000	810	890	960	1600
6,000	870	950	1040	1660
8,000	1030	1120	1220	1760
10,000	1180	1280	1360	1860
12,500	1350	1420	1530	1950

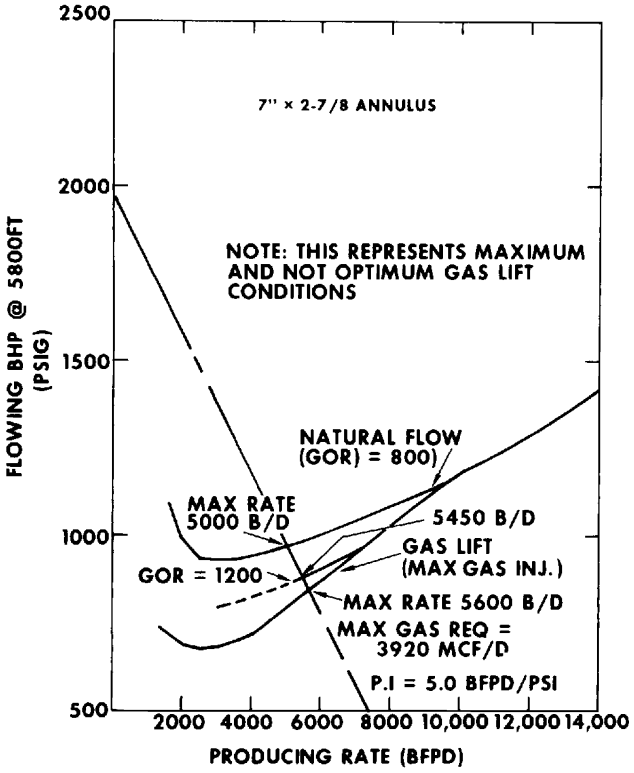


Fig. 2-8 — Comparison of natural flow with gas lift, 100% oil, no injection gas limit

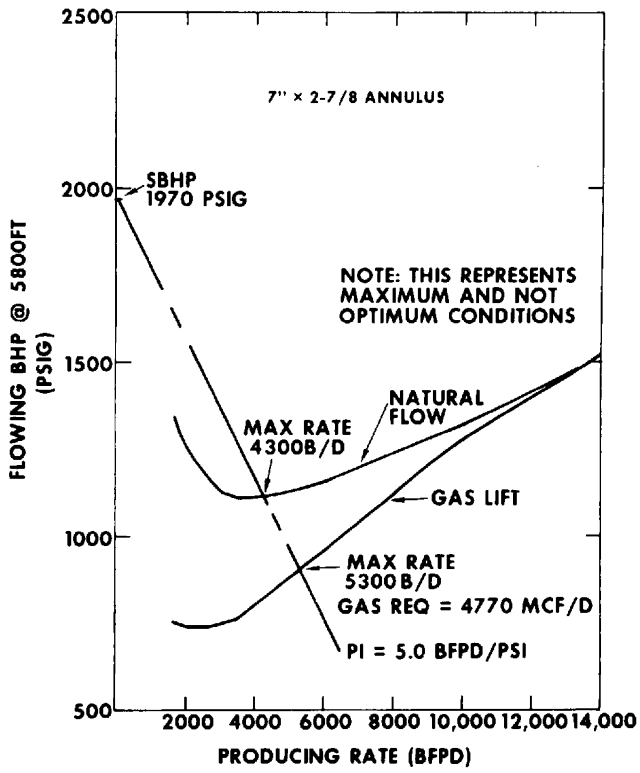


Fig. 2-9 — Comparison of natural flow with gas lift, 25% water, no injection gas limit

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(5450 B/D) under the limited gas injection rate of 2180 MCF/Day to the oil produced (5600 B/D) at a maximum gas injection rate of 4770 MCF/D.

Plots of curves comparing gas lift and natural flow at 25%, 50% and 75% water cuts and with no injection gas limit are shown in Fig. 2-9, 2-10 and 2-11.

TABLE 2-3
COMPARISON OF MAXIMUM PRODUCING RATES FOR NATURAL FLOW AND GAS LIFT

Water %	Max. Rate Nat. Flow (B/D)	Max. Rate Gas Lift (B/D)	Inj. Gas Required (MCF/D)
0	5000	5600	3920
25	4300	5300	4770
50	-0-	5000	5500
75	-0-	2600	3380

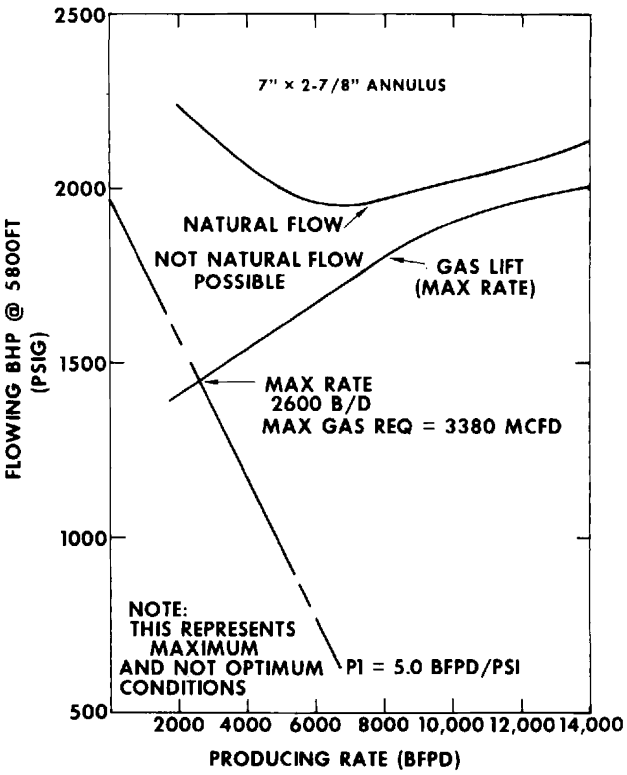


Fig. 2-11 — Comparison of natural flow with gas lift, 75% water, no injection gas limit

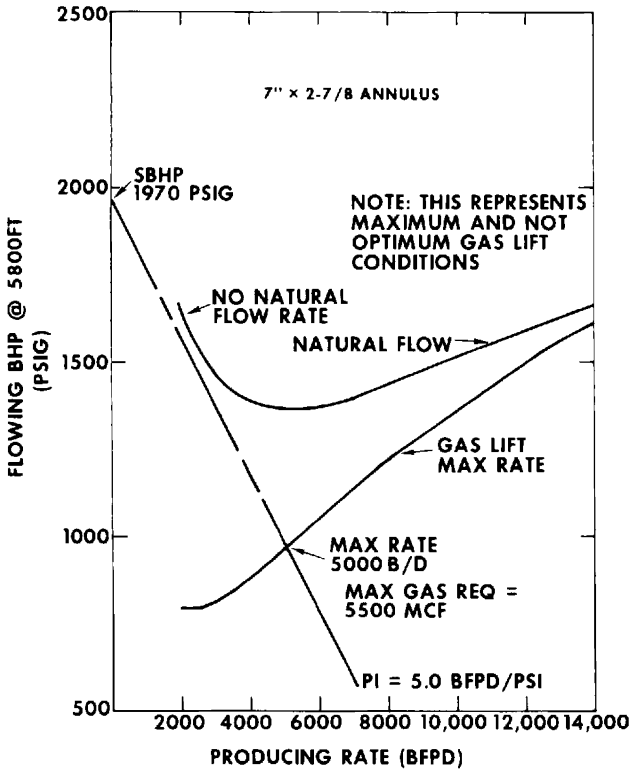


Fig. 2-10 — Comparison of natural flow with gas lift, 50% water, no injection gas limit

Comparison of Conduit Size

The effect of conduit size on maximum producing rate can be seen by comparing bottomhole flowing pressure versus rate curves prepared for the various pipe sizes under consideration. In the example problem, flow through $2^{7}/_{8}$ inch tubing was considered as an alternative to annular flow. Fig. 2-12 shows a plot of the flowing pressure versus rate curves for various water cuts in $2^{7}/_{8}$ inch tubing. The maximum flow rate at each water cut is shown in the table on Fig. 2-12.

The effect of changing static bottomhole pressures or formation productivity on producing rates can be determined by replotting the productivity line for the new productivity and with a new static pressure starting point.

Effect of Surface Operating Conditions

To calculate the effect of surface operating conditions, such as back pressure, on well production, curves should be prepared for a variety of possible surface operating pressures and a comparison made of the producing rates under each condition. Such comparisons are useful in determining the production to be gained from reducing pressure losses in production facilities. They may also be used for determining the optimum design operating pressure at the wellhead.

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Use of Inflow Performance Relationship Curves (IPR)

Although the example problem uses the straight line P.I. technique for predicting inflow performance, IPR curves can also be used for determining the point of intersection, which is, in effect, the balance point between inflow and outflow performance. An example of such a plot is shown in Fig. 2-13.

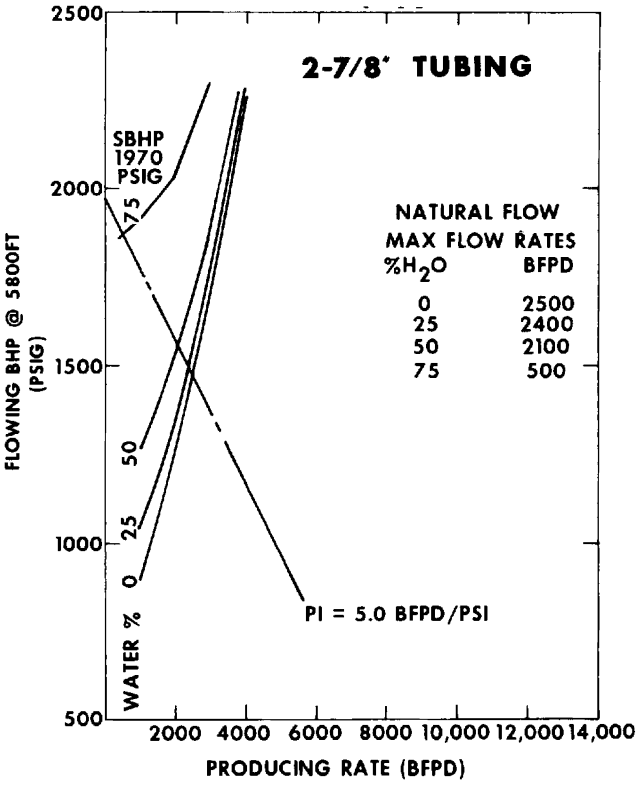


Fig. 2-12 — Natural flow, 2⅞-inch tubing

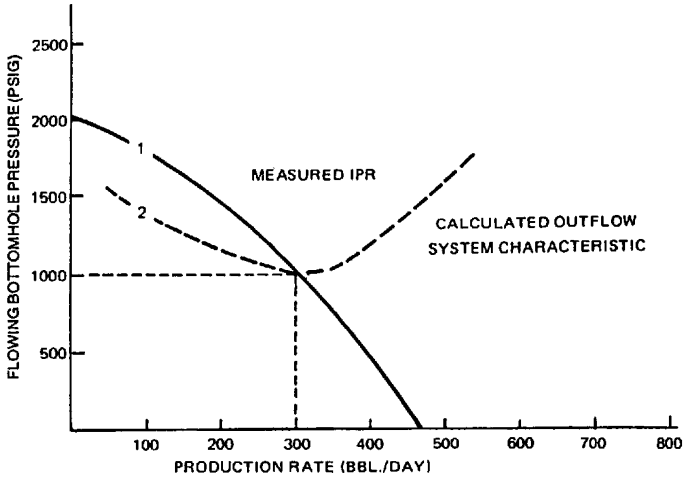


Fig. 2-13 — Curve number (1) is an IPR curve and curve number (2) indicates the calculated performance characteristics of the outflow system

Computer Programs for Well Performance Analysis

Computer programs are available that compare well inflow performance (productivity) with the vertical flow characteristics of the production installation to determine the maximum production rates that are possible under various producing conditions. These programs are usually available as adjuncts to gas lift design programs but can be used as separate tools for well performance analysis.

Most of the computer programs follow very closely the manual technique discussed in this chapter. However, the computer versions usually allow the user to input a wide variety of producing parameters and to study the effect of each of the parameters on well performance. Many of the computer programs will also plot the information in a graphic form similar to that shown in Fig. 2-14. This demonstrates the effect of injection gas pressure on producing rate and injection gas requirements. The great advantage of the computer programs is that they allow the generation of a large number of such curves comparing various producing parameters in a very short period of time.

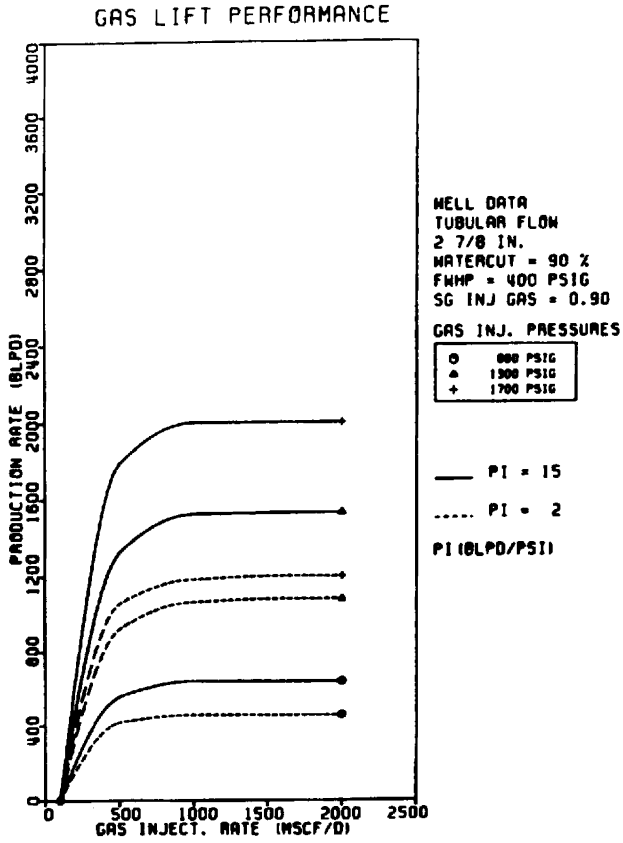


Fig. 2-14 — Computer plots of gas lift well performance

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CHAPTER 3
MULTIPHASE FLOW PREDICTION

INTRODUCTION

There are several words and terms in this chapter which may be new or confusing to the reader who is not familiar with multiphase flow studies. A definition of all terms is not necessary for understanding the basic concepts, but a discussion of the more unique terminology should aid the reader.

Dimensionless Parameters

Most multiphase flow correlations involve numerous dimensionless groups or parameters. Dimensionless groups are commonly used in the analysis of experimental data because the number of measured or assumed values for variables can be greatly reduced by combining several variables into a single dimensionless group of variables. The variables are combined in such a manner that all units will cancel, thus the group becomes independent of the unit system. Reynolds number is an example of a dimensionless parameter or group.

Empirical Data

The word empirical refers to measured data. When there is no purely mathematical relationship that will accurately predict the value of a variable or parameter associated with multiphase flow. The value must be established empirically by actual measurements. Generally, interpolation of empirical data will present no problem but extrapolation can be quite dangerous. Interpolation means the determination of values between measured data, whereas extrapolation refers to predicting values beyond the range of the measured data. For example, the investigator does all of the experimental work in 1¼-inch nominal tubing. A general computer program is developed based on these test data for 1¼-inch nominal tubing and extended to high rates through large tubing such as 4½-inch O.D. Predictions beyond the range of a correlation may be totally in error. Usually a correlation is identified by the investigator or investigators. A typical multiphase flow correlation consists of numerous equations and curves defining the relationships between different independent dimensionless groups, which may be called correlating parameters. These relationships represent measured data that have been organized in a manner that will permit calculation of the flowing pressures at depth or pressure loss through a flowline based on a production conduit size and the fluid rates and properties. Production conduit is a general term which can mean tubing or tubing-casing annulus, depending upon which is the production string. Most wells are produced through a tubing string.

Basis for Developing Multiphase Flow Correlations

Several of the earlier multiphase flow correlations were based on a total energy loss factor or a no-slip homogeneous mixture for high rate production. The total energy loss factor is analogous to a single-phase friction factor. No-slip homogeneous flow implies that the gas and liquid have the same velocity; therefore, the density of the mixture can be calculated for any desired pressure without a complex gas-slippage or liquid holdup correlation. In other words, the pressure loss calculations for multiphase flow and single-phase flow are similar. The distribution of the liquid and the gas is based on the daily production rate with no accumulation of liquid in the production conduit. These simplified methods for calculating multiphase flow pressure loss, with a total energy loss factor or a no-slip homogeneous mixture and friction factor, do not require the establishment of the flow regime or pattern. The flow regime for multiphase flow must be determined before the pressure loss can be calculated for the more general type of correlation. Each flow regime has a different set of equations and correlating parameters for calculating a pressure loss. If the flow regime cannot be accurately determined, the calculated pressure loss will be in error and discontinuities in the slope of the flowing pressure gradient curves may be apparent.

Multiphase flow in a production conduit represents complex relationships between many variables and dimensionless groups. For the purpose of this discussion, multiphase flow implies the presence of free gas and a liquid which may be oil and or water. Many of the important correlating parameters must be determined empirically because mathematical solutions do not exist. There is no one multiphase flow correlation available today that is universally accepted by the petroleum industry for accurately predicting flowing pressure gradients in all sizes of production conduits for the ranges of gas and liquid rates encountered in oil field operation. There is a continuing effort to develop new correlations and to improve those that exist.

Accuracy of Flowing Pressure at Depth Predictions

Accurate flowing pressure at depth predictions in production conduits are essential to efficient continuous flow gas lift installation design and analysis. Selecting the best correlation for specific well production rates and conduit sizes is not always a simple matter. Flowing pressure at depth surveys with calibrated instruments and accurate stabilized production data measured during the surveys are

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essential to verify the applicability of a multiphase flow correlation. In other words, the only way to properly evaluate a multiphase flow correlation or set of flowing pressure at depth gradient curves is to compare reliable well test data with calculated pressures at depth or with pressures determined from published gradient curves.

Importance of Reliable Well Test Data

Reliable well test data implies accurate gas measurement. The importance of selecting the recommended orifice beta ratios for accurate gas measurement cannot be overemphasized because the volumetric gas rate is one of the most important parameters for defining the flow pattern or regime. Beta ratio is the ratio of the size of the borehole in the orifice plate to the internal diameter of the meter tube. A differential reading in the upper two-thirds of the range of the element is essential for accurate gas measurement with an orifice meter, and the beta ratio controls the differential pen reading for a given volumetric gas rate. The proper equations for multiphase flow calculations depend upon a correct prediction of the flow regime for the general type of multiphase flow correlations. There are required well and tubular conditions before accurate flowing-pressure-at-depth predictions can be anticipated. The multiphase flow correlations in this discussion are not applicable when an emulsion exists. The production conduit must be full open: i.e., the area open to flow cannot be restricted by scale or paraffin deposition. For accurate predictions the flow pattern should also be relatively stable without severe heading or surging.

There have been many instances when a multiphase flow correlation or set of gradient curves has been rejected based on reportedly reliable well test data after the calculated flowing pressures at depth did not approximate the measured pressures at depth. Further investigation of the reported production test data may reveal the reason for the discrepancy. A practice of reducing the flow rate to run a survey is not uncommon when the wireline operator has difficulty lowering the subsurface pressure gage into the production conduit. Field personnel may report the average daily production rate as gas-liquid ratio for a well based on previous production test or an average daily rate for the last 30 days rather than obtaining accurate production test measurements during the survey.

Flowing pressure gradient curves and computer calculated flowing pressures at depth which are based on a proven multiphase flow correlation will assure consistent predictions in the stable flow range of the correlation. When the actual reported field data are inconsistent and not repeatable, the flowing pressure at depth predictions based on computer calculations are generally more accurate than the "so called" field measurements. An operator should always double-check the field data before condemning a widely proven multiphase flow correlation.

PUBLISHED VERTICAL, HORIZONTAL AND INCLINED MULTIPHASE FLOW CORRELATIONS

This discussion is not intended to replace a text book on multiphase flow. Only the multiphase flow correlations that have received at least limited acceptance by the petroleum industry are mentioned in this chapter. These vertical multiphase flow correlations are the Poettmann and Carpenter[3], Baxendell and Thomas[4], Duns and Ros[5], Johnson[6], Hagedorn and Brown[7], Orkiszewski[8], and Moreland[9]. The number of detailed investigations of horizontal and inclined multiphase flow are less numerous in the literature. The more widely applied correlations include Baker[10], Lockhart and Martinelli[11], Flanigan[12], Eaton[13], Dukler, et al[14], and Beggs and Brill[15]. The Beggs and Brill correlation for inclined flow may be used for vertical flow calculations by assigning a 90 degree angle of inclination. The reported data base, application and possible limitations are not always available for all multiphase correlations. Generally, internal company improvements and modifications in multiphase flow correlations and computer programs are not public knowledge. Only published information can be used to describe the various multiphase flow correlations.

Papers Evaluating the Accuracy of Multiphase Flow Correlations

There are technical papers [16, 17, 18, 19] that reportedly evaluate the accuracy of several widely used correlations for vertical multiphase flow. Generally, authors of these papers use published data from several sources. These may include flowing pressures at depth and production data from original publications for multiphase flow correlations being compared. A statistical error analysis is performed on the difference between the published measured pressure loss and the calculated pressure loss using computer programs written by these authors. The conclusions from this type of error analysis can be misleading to the reader. A multiphase flow data bank as a benchmark test for all multiphase flow correlations does not always apply. A significant portion of the data may be out of the recognized production rate or production conduit size ranges, noted by the investigators, to be applicable to their multiphase flow correlations. An example is the use of low production rate data to check the Baxendell and Thomas correlations.

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The Baxendell and Thomas correlation is a high rate extension of the Poettmann and Carpenter total energy loss factor curve. All low rate data would be on the Poettmann and Carpenter portion of the curve and not on the extension by Baxendell and Thomas. Another consideration is the manner in which a computer program is written and the correlations that are being used to calculate the fluid properties. The results from two computer programs based on the same multiphase flow correlation can be quite different.

Ros-Gray and Duns-Ros Correlations

Authors may infer that the Ros-Gray correlation, which can be purchased from Shell Oil Company, is being compared to other correlations when in fact the Duns and Ros correlation is being compared. The initial paper, which was based on an extensive laboratory investigation by Ros[20] was presented at a Joint AIChE-SPE Symposium and a revised version of the same paper was published in the *Journal of Petroleum Technology*[21]. The final version of the Ros paper was presented by Duns[5]. The Duns and Ros paper is based on laboratory data only and is not the Ros-Gray correlation that was modified to eliminate discrepancies between calculated and accurately measured data from over 600 actual stabilized well tests. The conclusion remains that one particular multiphase flow correlation may prove to be more accurate than others for certain production conduit sizes and rates; therefore, a ranking of the available correlations in terms of general overall applicability is questionable.

SIMPLIFIED MULTIPHASE FLOW CORRELATIONS BASED ON TOTAL ENERGY LOSS FACTORS OR NO-SLIP HOMOGENEOUS MIXTURES

A simplified multiphase flow correlation based on a total single energy loss factor curve or a simple homogeneous no-slip flow model should be considered for calculating flowing pressures at depth in areas of high rate production when the correlation is based on accurate stabilized flowing well data from the same field or similar well production rates and conduit sizes. The calculations for this type correlation are simple and are reported[22, 23] to be more accurate in many instances than the more complex general type of correlations.

Poettmann and Carpenter Correlation

The first widely accepted multiphase flow correlation was developed by Poettmann and Carpenter and was published in 1952. The work of Poettmann and Carpenter did more to initiate additional research in vertical multiphase flow than all prior publications combined. Their correlation was based on a total single energy loss factor that accounts for all losses including liquid holdup from gas slippage and for friction and acceleration. The energy balance equation combined a pseudo no-slip homogeneous mixture density gradient and the Fanning equation for single-phase flow where the friction factor was replaced by the total energy loss factor.

Baxendell and Thomas Correlation

Baxendell and Thomas modified the Poettmann and Carpenter correlation using measured data from high rate wells in Venezuela. The total energy loss factor curve was extended for daily mass rates which were significantly higher than the original Poettmann and Carpenter data. The energy loss factor for vertical and horizontal multiphase flow approached a near constant value at very high daily mass rates in a manner analogous to high Reynolds numbers for fully turbulent single-phase flow on a Moody diagram. The authors assumed that the flattened portion of the energy loss factor curve represents the truly turbulent conditions where little or no gas slippage occurs. The calculated flowing pressures at depth for high rates based on the extended total energy loss curve proved to be exceedingly accurate for wells in Venezuela. Since extension of the energy loss curve was based on well data from the same fields in which the correlation was being used, reasonable accuracy in flowing pressure at depth predictions could be anticipated. The number of variables which affect these pressure predictions are reduced because the fluid properties and conduit sizes are the same for the correlation and the actual wells. The original Poettmann and Carpenter total energy loss factor curve and the extension by Baxendell and Thomas is shown in Fig. 3-1.

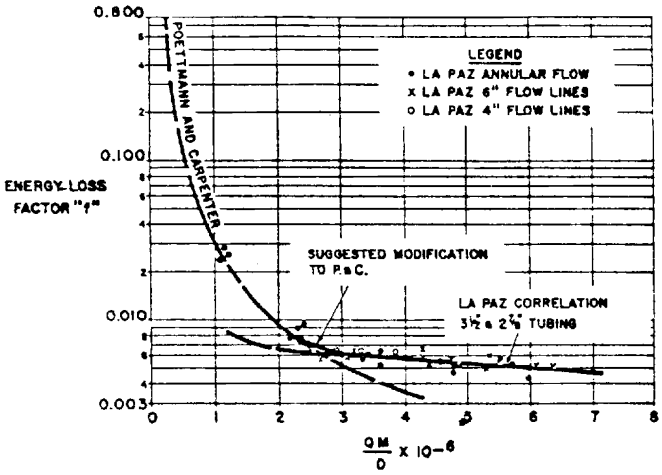


Fig. 3-1 — Extension of the energy loss factor curve by Baxendell and Thomas[4] (Copyright 1961, SPE-AIME, First published in the JPT 1961)

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Two-Phase Homogeneous No-Slip Mixture Correlations

Several technical papers have been published that illustrate the application of two-phase homogeneous no-slip correlations for high rate wells. Brown[22] notes that a simplified correlation developed from multiphase flow data for an actual production conduit size may assure more accurate pressure loss calculations than the more complicated general type of correlation based on laboratory controlled multiphase flow data for conduit sizes which are generally smaller and shorter than the actual conduits. The importance of properly defined fluid property relationships for calculating flowing pressure gradients was demonstrated by Cornish[23]. The advantages and accuracy of a simplified total single energy loss factor correlation or a two-phase homogeneous no-slip flow model based on actual measured data from high rate production wells should not be overlooked. Total energy loss factors are easily calculated from flowing pressure surveys, and an energy loss factor curve can be shifted to improve the accuracy of the calculated flowing pressures at depth.

GENERAL TYPE MULTIPHASE FLOW CORRELATIONS

A general type of multiphase flow correlation is reportedly applicable for all sizes of typical oil field production conduits and for the liquid and gas rates encountered in oil field operations. The general correlation requires an identification of the flow regime, or flow pattern, to define the proper equations for calculating the flowing pressure gradient in the incremental pipe length under investigation. There may be more than one flow pattern existing between the lower end of the production conduit and the surface. The flow regime may be single-phase or bubble flow at the higher pressures nearer the surface. The flow pattern schematic from Moreland[9] in Fig. 3-2 for vertical flow of gas-liquid mixtures illustrates the need for proper flow regime identification. The pressure gradient equation for at least one flow regime will include liquid holdup based on gas slippage. Liquid holdup represents the relationship between the volume occupied by the liquid and the total volume of the production conduit within the incremental pipe length under investigation. The accuracy of the method for predicting liquid holdup is particularly important for the gas and liquid velocities associated with the lower production rates. Liquid and gas viscosity's and surface tension are usually required input or are default values in the computer programs for the general types of multiphase flow correlations. Accurate pressures at depth predictions are claimed by the developers of most general correlations for even relatively high viscosity crude oil.

Typical Pressure Gradient Equation for Vertical Flow

Although the exact final equations and correlating parameters vary between investigators, the basic typical pressure gradient equation for vertical multiphase flow consists of the following terms:

Equation 3.1

$$\text{Pressure Gradient Term} = \text{Density Term} + \text{Friction Term} + \text{Acceleration Term}$$

The density term includes a liquid holdup correction for gas slippage. The acceleration term is often neglected in all flow regimes except where high fluid velocities exists such as

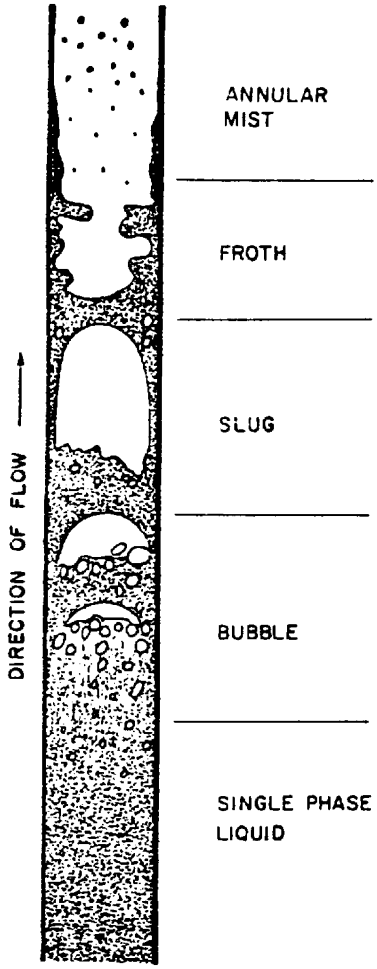


Fig. 3-2 — Typical flow patterns for vertical flow of gas-liquid mixtures[9]

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in the annular mist regime. The contribution of acceleration is reported to be very small in the other multiphase flow regimes.

The flow regime, or flow pattern, map generally is divided into at least three major regions which are defined by the continuity, or lack of continuity, of the liquid and gas phases. Fig. 3-3 is the published Ros flow regime map based on laboratory data. The liquid phase is continuous in Region I; and gas is the continuous phase in Region III. The pressure gradient in the transition area between Regions II and III can be approximated by linear interpolation on the basis of the gas velocity number (RN) value on the abscissa, where R is the ratio of the in-situ superficial velocity of the gas to liquid phases. The flow regime must be established before the proper equations and correlations can be selected for the flowing pressure gradient calculations. The Ros flow regime boundary equations have been used by other investigators.

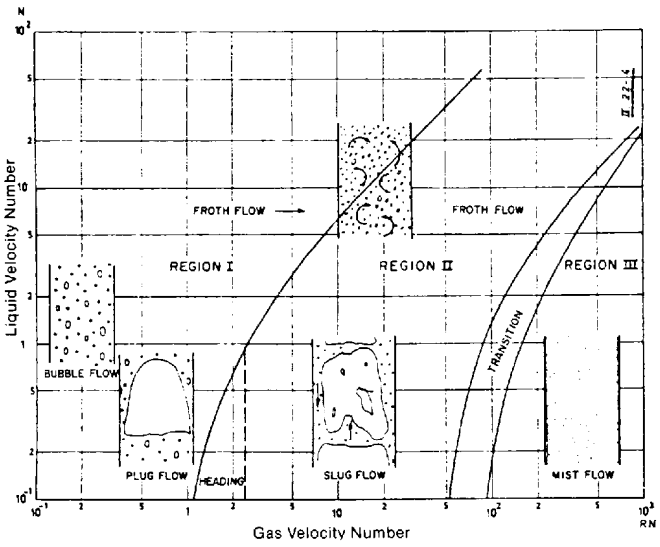


Fig. 3-3 — Ros flow region boundaries based on laboratory data[5]

Published General Type Correlations

The multiphase correlations developed by Ros, Orkiszewski, Aziz, et. al, are considered general. The original paper by Hagedorn and Brown[7] stated that it was unnecessary to separate two-phase flow into the various flow patterns and develop correlations for each pattern. Many computer programs based on the Hagedorn and Brown correlation include separate sets of equations for the different flow regimes and use the Hagedorn and Brown correlations for only the slug flow pattern, which is Region II on the Ros flow regime map in Fig. 3-3. An explanation for this conclusion by Hagedorn can be found in the paper by Orkiszewski which notes that slug flow occurred in 95 percent of the cases studied. Apparently, Hagedorn did not encounter the bubble flow regime during his experimental work because his tests were conducted in a shallow 1500-foot well. The accepted categories or flow regimes for two-phase flow are ideally depicted by Orkiszewski in Fig. 3-4.

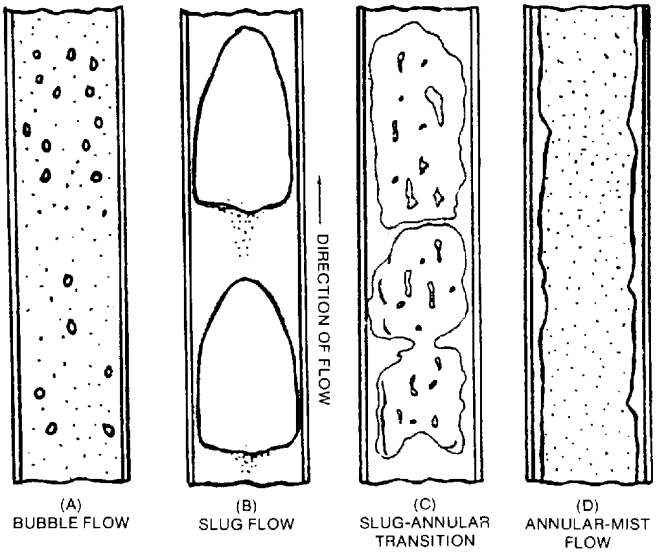


Fig. 3-4 — Ideal flow regimes or categories for multiphase flow as illustrated by Orkiszewski[8] *(Copyright 1967 SPE-AIME, First published in the JPT, June 1967)*

DISPLAYS OF FLOWING PRESSURE AT DEPTH GRADIENT CURVES

Most displays of flowing pressure at depth gradient curves use the same parameters but may be plotted somewhat differently. Generally, a set of gradient curves will be displayed for a given conduit size, a production rate, and a water cut which may be zero; i.e., all oil production. Flowing pressure at depth curves will be drawn for gas-liquid ratios (R_{gl}) ranging from zero for single-phase liquid to a maximum practical R_{gl}, depending upon the conduit size and production rate. For example, a maximum R_{gl} of 10,000 standard cubic feet of gas per stock tank barrel (scf/STB) would be displayed for a production rate of only 100 STB/day through $2^{7}/_{8}$-inch O.D. tubing, whereas a R_{gl} of 1000 to 2000 scf/STB may be the maximum for a higher production rate of 2000 STB/day through the same conduit size. In general, higher R_{gl} values are associated with lower production rates and lower R_{gl} values with higher production rates.

Converting R_{go} to R_{gl}

This family, or set, of curves should always be defined in terms of R_{gl} and not gas-oil ratio (R_{go}). The R_{go} is equal to the R_{gl} only when the water cut is zero. The first step after selecting the proper set of gradient curves is to convert the

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total R_{go} to total R_{gl} before determining a flowing pressure at depth.

$$R_{gl} = f_o (R_{go}) \qquad \text{Equation 3.2}$$

Where:

R_{gl} = gas-liquid ratio, scf/STB
f_o = oil cut (1.0 - water cut), fraction
R_{go} = gas-oil ratio, scf/STB

These R_{gl} curves always represent total R_{gl}, which is the formation R_{gl} below the point of gas injection and is the injection plus the formation R_{gl} about the point of gas injection.

Gilbert's Curves

Gilbert[1] published one of the first sets of flowing pressure at depth gradient curves in 1954. Although flowing pressure gradient curves for several conduit sizes were published by Gilbert, the only full-page size curves presented in the API paper were for $2^7/_8$-inch O.D. tubing. No multiphase flow correlation was offered for calculating these flowing pressures at depth. Gilbert's curves were based on numerous flowing pressure surveys run in the Ventura Field in California. The Gilbert flowing pressure-depth curves were the forerunners for the present method of displaying gradient curves. One set of Gilbert gradient curves for 600 barrels per day through $2^7/_8$-inch O.D. tubing is shown in Fig. 3-5.

Note that the depth axis is shifted 5000 feet for the R_{gl} curves of 3000, 4000 and 5000 scf/STB. The optimum R_{gl}, as defined by Gilbert for this daily production rate of 600 barrels through $2^7/_8$-inch O.D. tubing, is 240 scf/STB. The optimum curve represents the minimum possible flowing pressure at depth for a given conduit size and production rate. When the R_{gl} exceeds 2400 scf/STB, the flowing pressure gradient begins to increase rather than decrease. This increase in flowing pressure gradient is referred to as a reversal in the slope of a gradient curve. A higher flowing pressure at depth is predicted for R_{gl} of 5000 scf/STB than for 2400 scf/STB based on these gradient curves.

Minimum Fluid Gradient Curve

Many published gradient curves are displayed with a minimum fluid gradient curve rather than shifting the origin of the depth scale to prevent overlaying and crossing over of R_{gl} curves at low flowing pressures at depth. A reversal in the slope of a high R_{gl} curve will result in the higher R_{gl} curves crossing over the low R_{gl} curves at low flowing pressures. An example of overlaying of gradient curves[24] is illustrated in Fig. 3-6. and accurate pressure determinations are difficult and confusing at the lower flowing pressures where the curves are crossing over one another.

The minimum fluid gradient curve ignores the reversals in the individual R_{gl} curves and represents a flowing pressure gradient curve defined by the loci of tangency's of the higher R_{gl} curves to form a single curve. As the R_{gl} increases, the flowing pressure at the depth of tangency for the higher R_{gl} curves increases which infers that these points of tangency occur at increasing chart depths. A set of typical flowing pressure gradient curves for 600 STB day through $2^3/_8$-inch O.D. tubing[25] is shown in Fig. 3-7. The minimum fluid gradient curve and higher R_{gl} curves will be one and the same above the point of tangency. Gradient curves displayed with a minimum fluid gradient curve are easier to apply for certain design determinations. The design calculations may lose some accuracy if gas lift operations should occur in the reversal portion of a high R_{gl} curve. However, most efficient gas lift installations will operate with a total R_{gl} below the range of a severe reversal in the flowing pressure gradient curve and the actual flowing wellhead pressure will exceed the lower pressures where a severe reversal would occur. Gas lift installation designs and analyses have been based on gradient curve displays with a minimum fluid gradient curve without any reported significant error in predictions of flowing pressures at depth or injection gas requirements.

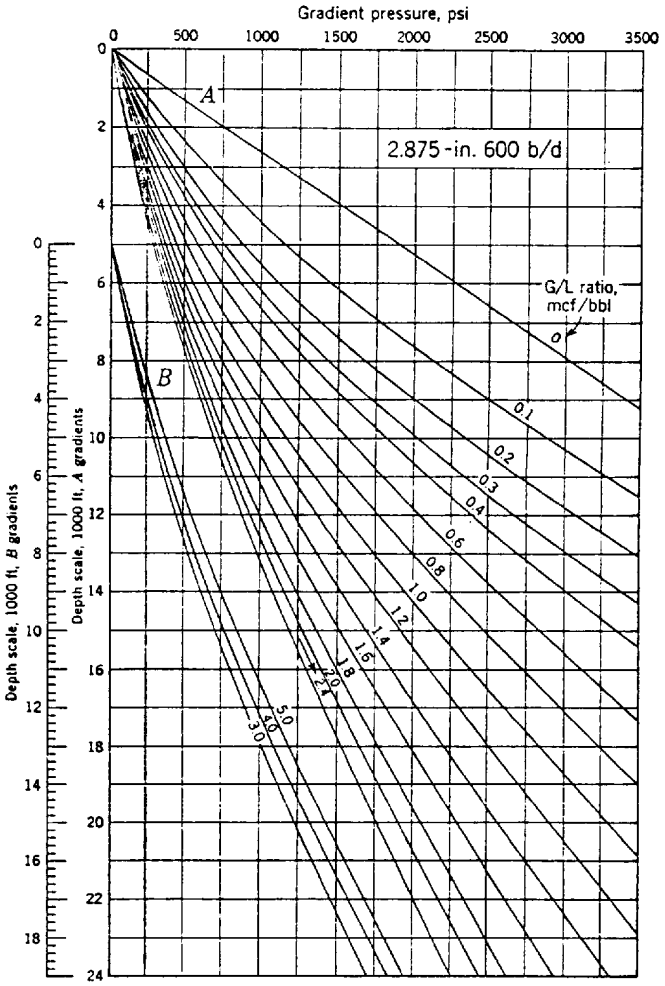


Fig. 3-5 — Gilbert's flowing pressure gradient curves for 600 BPD through $2^7/_8$-inch O.D. tubing[1]

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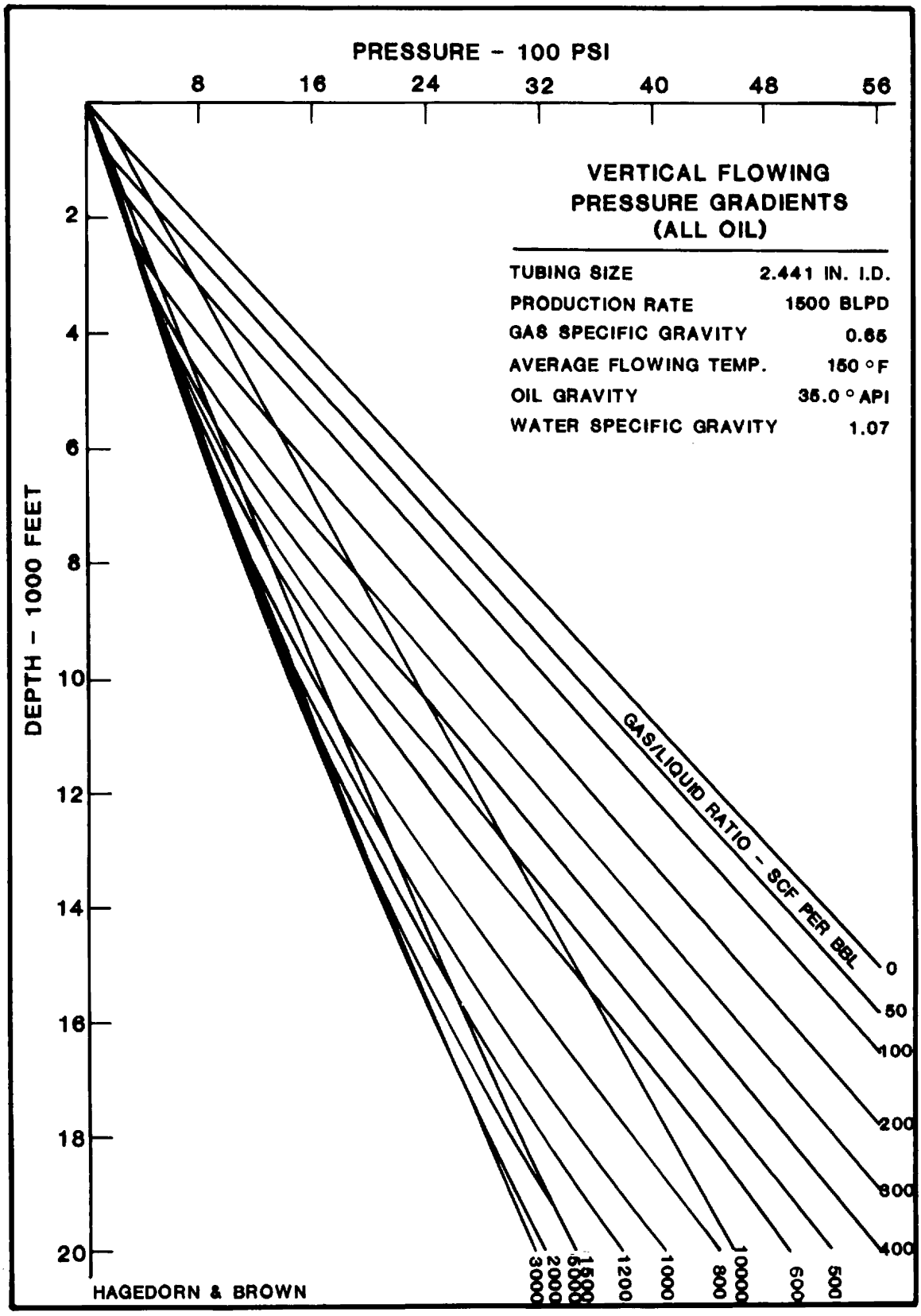


Fig. 3-6 — Vertical flowing pressure gradient curves without depth displacement to eliminate overlapping of the high R_{gl} curves[24]

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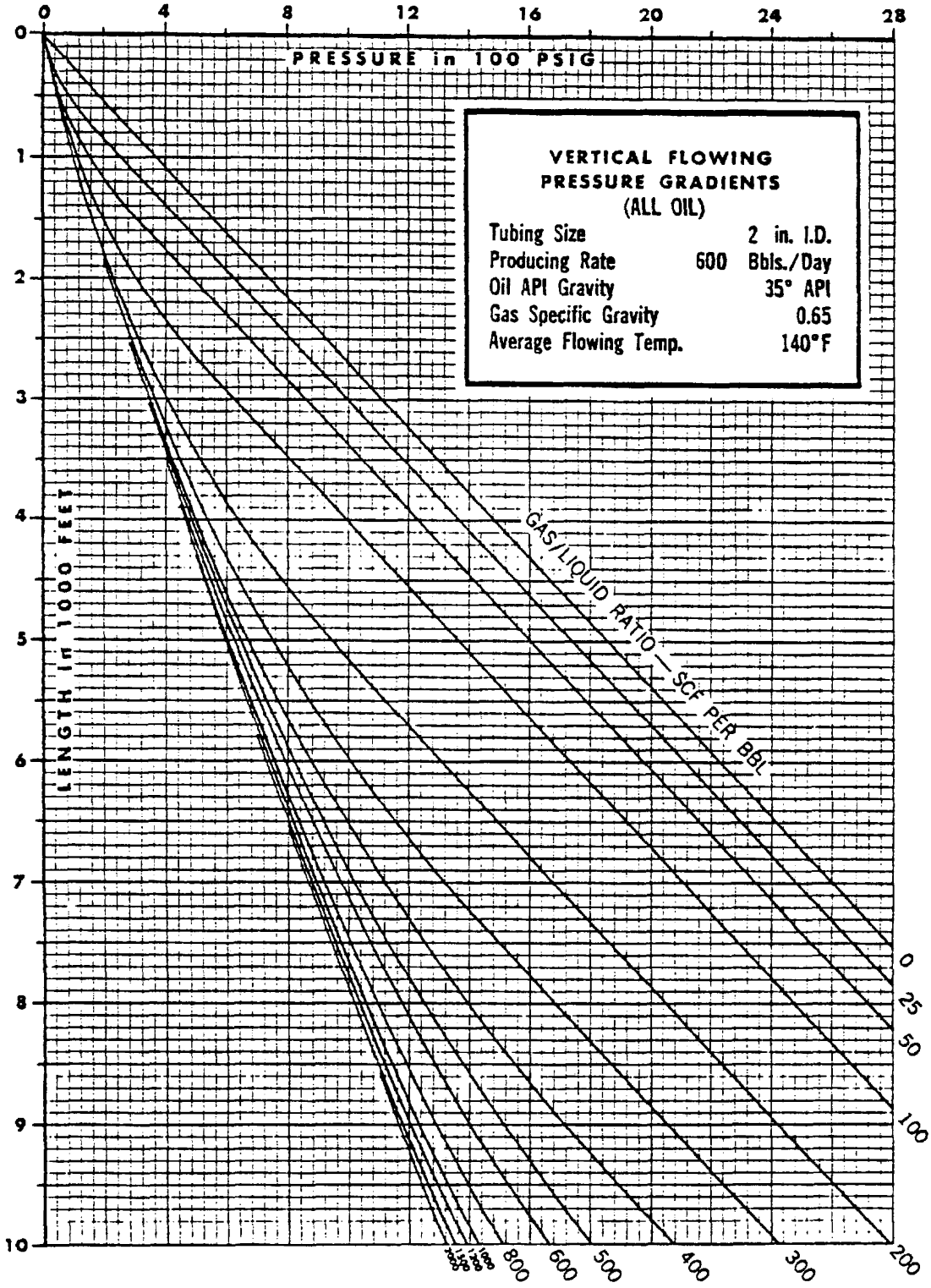


Fig. 3-7 — Vertical flowing pressure gradient curves plotted with a minimum fluid gradient curve[25]

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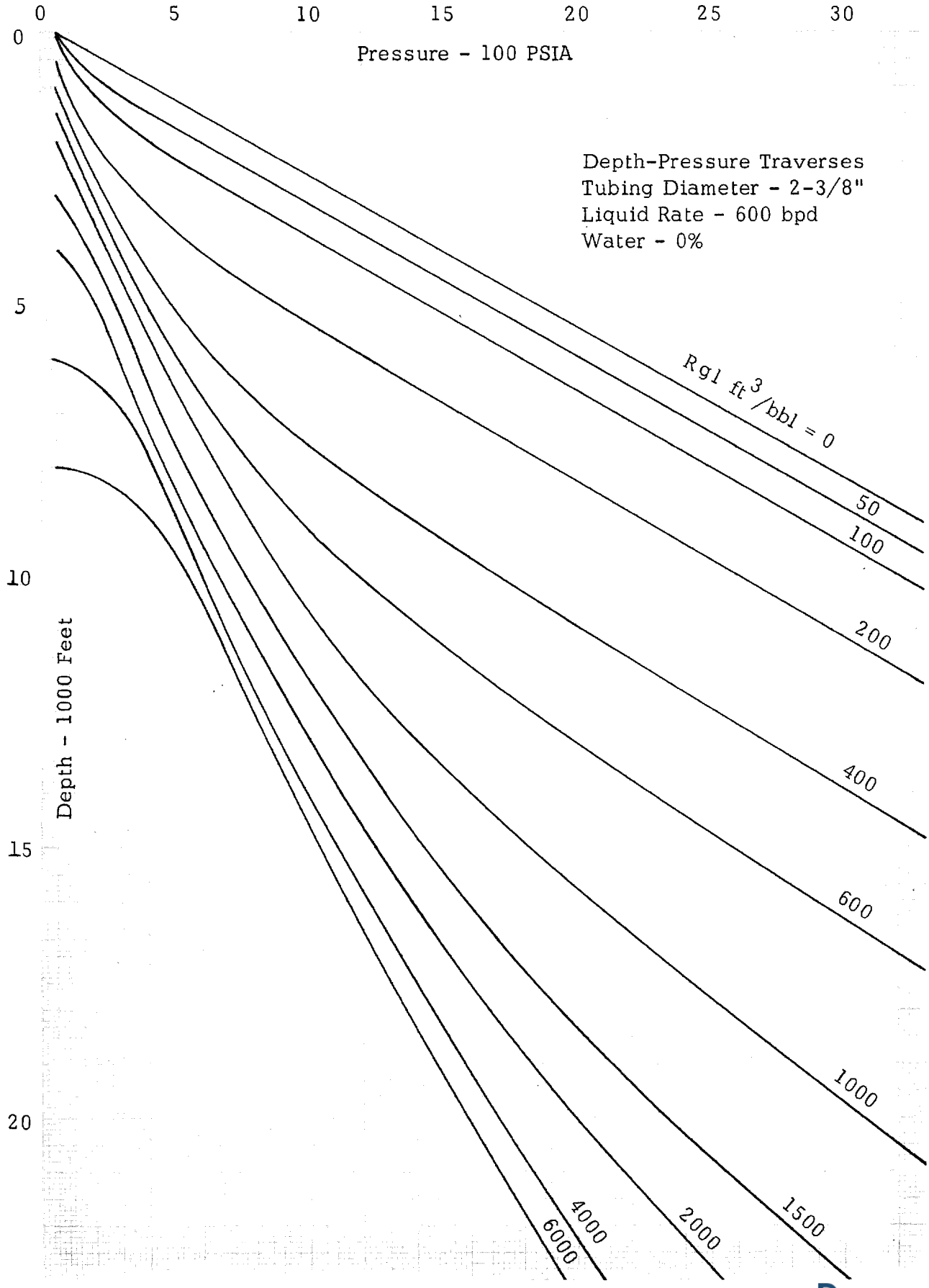


Fig. 3-8 — Vertical flowing pressure gradient curves based on the Shell Ros-Gray correlation with the higher Rgl curves displaced on the depth scale to prevent gradient reversal overlapping[6]

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Displaying Gradient Curves to Prevent Crossover

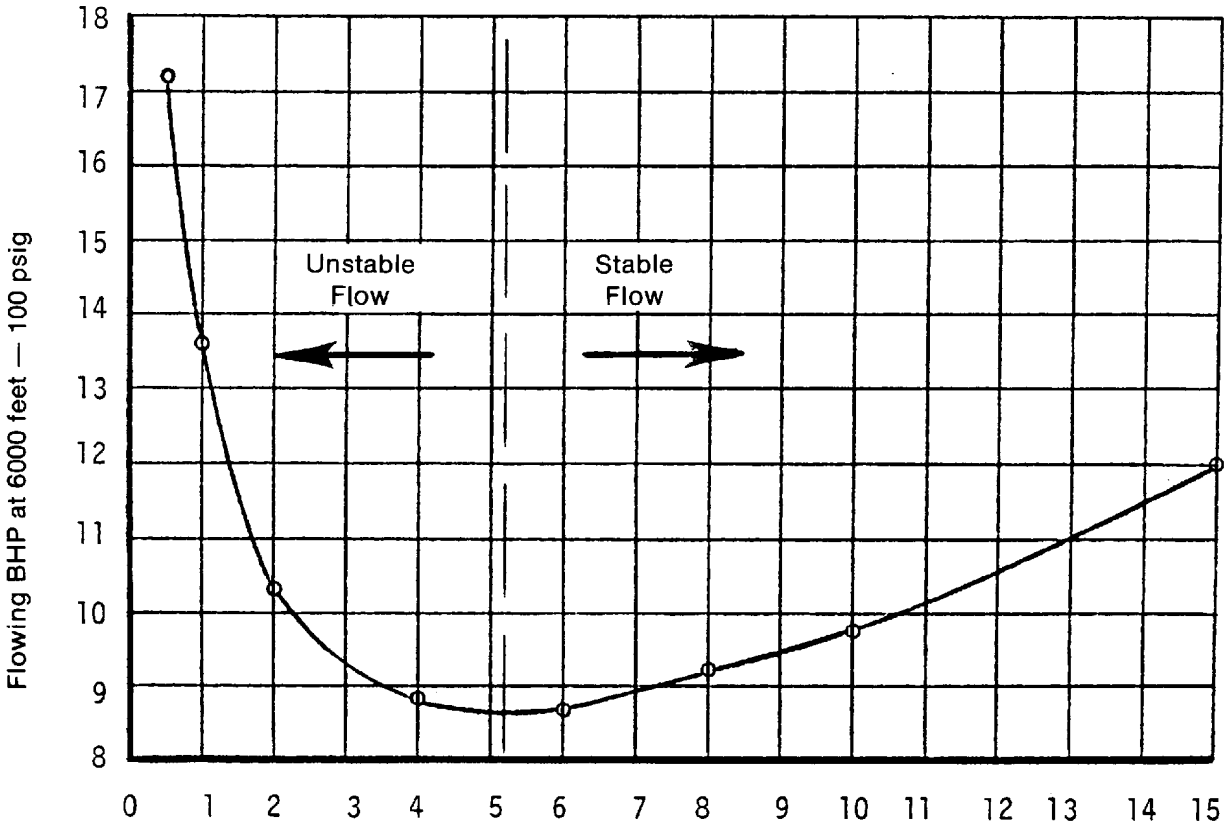
The most accurate display of gradient curves will include the reversal in the flowing pressures at depth for the higher R_{gl} curves. The R_{gl} curve will be displaced sufficiently on the depth scale to prevent the next higher R_{gl} curve from crossing over the preceding lower R_{gl} curve. A set of Ros-Gray curves[6] are shown in Fig. 3-8. Flowing pressures at depth are determined in the same manner for the displaced R_{gl} curves as for a set of gradient curves with a minimum fluid gradient curve.

STABILITY OF FLOW CONDITIONS AND SELECTION OF PRODUCTION CONDUIT SIZE

Multiphase flow correlations are developed based on stabilized flowing well data. A correlation can be extended beyond its range of validity without the user recognizing the limitations. Although smooth gradient curves may be published for low liquid rates with low total gas-liquid ratios, actual flow conditions may be quite different than would be predicted from the curves.

Graphical Determination of Minimum Stabilized Production Rate

A plot of flowing bottomhole pressure at 6000 feet versus daily production rate for a constant R_{gl} of 400 scf/STB and a flowing wellhead pressure of 100 psig is shown in Fig. 3-9. A minimum flowing bottomhole pressure of



Well Information:
1. Tubing Size = 2⅞-inch O.D.
2. Tubing Length = 6000 ft
3. Water Cut (f_o) = 0% (All Oil)
4. Formation R_{gl} = 400 scf/STB
5. Flowing Wellhead Pressure (P_{wh}) = 100 psig

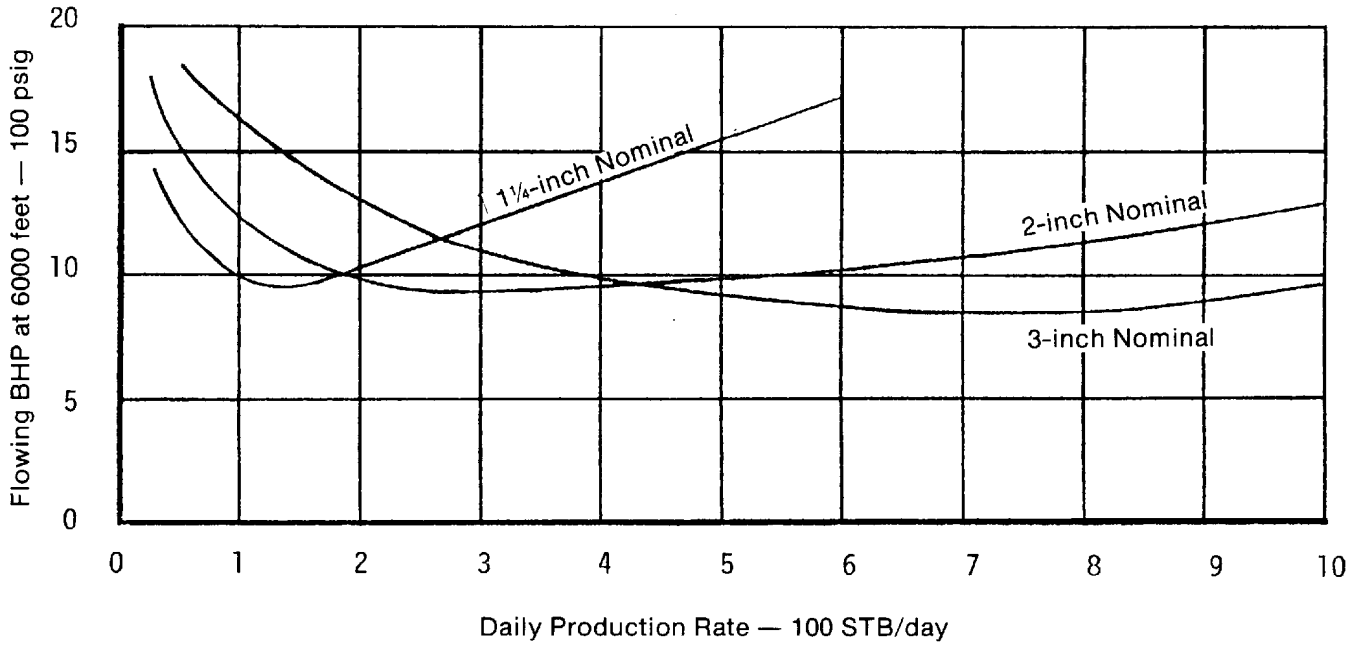
Fig. 3-9 — Flowing BHP versus daily production rate for a constant gas-oil ratio

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approximately 860 psig at 6000 feet occurs at a daily production rate slightly greater than 500 STB day. The flowing bottomhole pressure increases at lower and higher daily liquid production rates. The unstable flow conditions exist at daily liquid rates less than the rate for the minimum flowing bottomhole pressure. The unstable range should be avoided by producing at a daily rate that is safely above the 500 STB day in this example to assure not slipping into the unstable region. A cyclic heading or surging condition develops as the daily production falls below the liquid rate for this minimum flowing bottomhole pressure. The cyclic conditions are perpetuated and intensified by the fluid flow principles defining a vertical or inclined multiphase flow system and the inflow performance relationship defining the deliverability of a reservoir. As the liquid rate decreases, the flowing bottomhole pressure increases which in turn results in a further decrease in liquid rate. Most wells will reach a severe surging condition that can best be described as a loading and unloading state of flow before all flow ceases and the well is classified as dead.

Conditions Necessary to Assure Stable Multiphase Flow

An explanation for the conditions necessary to assure stable multiphase flow can be related to a minimum free volumetric gas rate requirement for a given production conduit size. The in-situ gas velocity must exceed a minimum value that prevents excessive gas slippage and correspondingly high liquid holdup which causes a well to load up and die. Since there is this minimum gas rate requirement, the total gas-liquid ratio to sustain stable flow must increase as the daily liquid production rate decreases for the same production conduit size. For this reason, a comparison of injection gas-liquid ratios is not recommended for evaluating the gas lift operations in wells that have a wide range in daily production rate. Also, a minimum gas velocity necessary to prevent excessive liquid holdup explains why stable flowing conditions can be established in smaller conduit sizes for low rate wells. The gas velocity increases as the production conduit size decreases for the same daily



Well Information:
1. Tubing Length = 6000 feet
2. Formation R_{gl} = 400 scf/STB (All Oil)
3. Flowing Wellhead Pressure = 100 psig

Fig. 3-10 — Flowing BHP versus daily production rate for three different tubing sizes of the same length and a constant gas-oil ratio

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volumetric gas rate. In other words, a tubing size can be too large for a low capacity well or too small for a large capacity well.

Effect of Tubing Size on Minimum Stabilized Flow Rate

A well may flow with a $2^3/_8$-inch O.D. tubing string and require artificial lift with a larger size tubing. If the daily production rate occurs in the unstable range of flow for a given tubing size, a lower flowing bottomhole pressure can be attained for the same daily production with a smaller conduit size. For example, the predicted flowing bottomhole pressure is approximately 1360 psig at 6000 feet for 100 STB day through $2^7/_8$-inch O.D. tubing in Fig. 3-9. If 1 660-inch O.D. ($1^1/_4$-inch nominal) tubing were run in the same well, the predicted flowing bottomhole pressure would decrease to approximately 1000 psig for the same daily production rate of 100 STB day. The intake flowing bottomhole pressure versus daily production rate for three commonly used tubing sizes is illustrated in Fig. 3-10. Accurate gradient curves can be used to select the proper conduit size for a well based on the desired daily production rate.

CONCLUSIONS

The ability to predict accurate multiphase flowing pressures at depth in a vertical production conduit has improved significantly since the work of Poettmann and Carpenter in 1952. Research in multiphase flow continues with increased emphasis in gathering systems including flowlines and inclined flow. The number of wells having deviated production conduits will increase as new wells are drilled from offshore platforms. Improved multiphase flow correlations will be developed for deviated production conduits. The calculations for inclined flow will be more complex by requiring profiles of production conduit length versus angle of deviation.

Many companies have their own in-house multiphase flow computer programs. These programs should be utilized by field production personnel for continuous gas lift installation design and analysis. The majority of the gas lift manufacturers have computer programs available to design and analyze gas lift installations. The widely used multiphase flow correlations in these computer programs have been verified by actual field measurement to be reasonably accurate when reliable well data are used for input. In conclusion, the advent of multiphase flow correlations which are applicable to the conduit sizes and the daily production rates associated with gas lift operations has changed the design and analysis of continuous flow gas lift wells from an art based on experience to a predictable science.

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CHAPTER 4
GAS APPLICATION AND GAS FACILITIES FOR GAS LIFT

INTRODUCTION

Gas handling facilities such as gas compressors, dehydrators, meters, and pipelines are the highest cost portions of the gas lift system. This equipment usually requires more operating and maintenance effort than any other part of the gas lift facilities.

Natural gas used to produce liquids by gas lift is controlled, measured, compressed, and processed with mechanical devices. Therefore, an understanding of gas fundamentals and operating practices is necessary to the successful operation of a gas lift system. Operating practices involving gas are different from those for oil because of the increased pressure and compressibility of the mixtures involved. Also, as a gas that contains even small quantities of hydrogen sulfide can be very corrosive to certain equipment and present a hazard to human life. It is important to understand that a single component gas like nitrogen and a mixture of components such as natural gas will behave differently.

Injection gas for gas lift wells can be affected by various operating and producing conditions including gas supply and production system back pressure. Production conditions such as surface wellhead back pressure and surface temperature are usually estimated in gas lift design and planning because actual measurements will not be available. Gas lift valves downhole will respond to injection gas pressure and production pressure in the wellbore as well as pressure and temperature inside the bellows of the gas lift valve. These conditions must be accurately predicted.

BASIC FUNDAMENTALS OF GAS BEHAVIOR

The pressure of a liquid or gas system can be measured. A pressure gage is the device that is commonly used to measure the pressure of the liquid/gas mixture produced from the well as well as the pressure of the gas injected into the well. The pressure is taken with a gage and is referred to as *gage pressure*. In the United States it is measured in pounds per square inch and designated psig. Gage pressure plus atmospheric pressure (usually about 15 psi) is referred to as *absolute pressure* and designated psia. The difference between gage pressure and absolute pressure is very small at high pressures. For example, 1000 psig converts to 1015 psia, if atmospheric pressure is 15 psi.

Gas lift systems utilize gas pressure in more than one type of application. In the first type of application the gas can expand. In this application, gas goes from the compressor, through a pipeline to the well, and then goes through a gas lift valve, where it expands and mixes with the produced liquids. At each link the gas expands and loses some of its pressure energy. The second type of application involves a sealed gas container. An example of this is the nitrogen which is contained in the bellows of a gas lift valve. In each of these cases the gas behavior differs. The sealed container is a system in which pressure, temperature, and volume are related.

In the sealed container, or bellows, a temperature increase causes a pressure increase inside the bellows because the nitrogen cannot expand outside the bellows. This is stated in the following equation:

$$\frac{P_1}{T_1} = \frac{P_2}{T_2} \qquad \text{Equation 4.1}$$

In gas lift calculations this equation could be used to determine the change that takes place in the nitrogen pressure in the bellows when a gas lift valve is set in a test rack at a temperature of 60°F and then is placed downhole at a much higher temperature. However, before equation 4.1 can be applied, the effects of temperature must be reviewed.

Temperature affects the gas in the closed container as well as in the open, expansive application. The indicator of heat change is the measured degree of temperature. In all calculations throughout this chapter, the temperatures are absolute, i.e., degrees Rankine (°F plus 460). For example, 150°F plus 460 is equal to 610° Rankine (absolute).

A gas expands when heated. Temperature increase after compression and the subsequent effect on flow through a pipeline or a gas lift valve are the most common examples of these phenomena. Gas measurement requires a record of the flowing temperature of the gas through an orifice meter. The gas flow equation is adjusted for the flowing temperature of the gas and corrected to a standard temperature of 60°F. In the calculations shown here, the temperature in degrees Fahrenheit (F) is converted to degrees Rankine (R).

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