Flowing and Gas-lift Well Performance†

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ABSTRACT
The paper describes the two-phase vertical-lift function, explains the hydraulics of natural flow, outlines two-phase flow through orifices, summarizes methods for estimating individual well capabilities, and includes approximations for solution of natural-flow and gas-lift problems for tubing of the 1.66-, 1.90-, 2.375-, 2.875- and 3.50-in. API sizes, and crude oils in the gravity range from 25 to 40 API.

INTRODUCTION
Advances in knowledge of the different lifting methods do not lend themselves to evaluation quickly or in simple economic terms. In the aggregate, however, they constitute the necessary basis for improved lifting policies and profitabilities, wherever oil is raised.

Production by natural flow rightly tops the list of lifting methods, inasmuch as it produces more oil than all other methods combined. It proceeds with minimum cost in relative absence of operating difficulties; and is relinquished finally in an atmosphere charged with regret, and supercharged with expletives intended to fortify the conclusion that the stoppage is an irreversible act of Providence. Nevertheless, production men have been haunted for years by the thought that a more definite knowledge of flowing performance would suggest means of resuming flow after premature stoppages, permit more effective well control, more appropriate flow-string selections, and serve in general to increase the proportion of oil quantities economically recoverable by natural flow.

Development of organized information on vertical flow has been so far a matter of slow growth. A presentation in 1930 of the basic theory by the late Professor Doctor J. Versluys† provided an initial impetus for current developments, but has been applied only to a limited extent because of practical difficulties in evaluating factors which appear in the Versluys differential.

An interesting attempt to solve the problem of two-phase vertical lift by testing flow through short (67-ft) tubes was reported in 1931 by T. V. Moore and H. D. Wilde.† Failure of this project to provide the desired generalization seems attributable to use of tube lengths so short that representative conditions were not attained. Kemler and Poole,‡ in a paper on flowing wells presented before the American Petroleum Institute in 1936, developed a limited correlation between gas-liquid ratio and pressure drop per unit of tubing length, and explained a method of estimating flowing life. The work of C. J. May and A. Laird§ resulted in vertical-lift generalizations well adapted to predict results within a restricted range of conditions. The interesting paper by Poettman and Carpenter‡ appeared subsequent to the time of derivation of the material here presented.

"Gas-Lift Principles and Practices" by S. F. Shaw,‖ the pioneer consultant on vertical flow, provides an interesting discussion of gas-lift history and methods with correlations which, though limited in scope, were none the less useful. Shaw's observation, that power functions may be applied in approximating the relationships between minimum gas-lift intake pressures and given liquid production rates, has been used here.

The excellent paper by E. C. Babson§ added considerably to knowledge of vertical flow, particularly in the range for gas-liquid ratios greater than 2.0 Mcf per bbl. To a large extent the present paper is a result of reviewing Babson's data and work after adding a considerable fund of depth-pressure information involving gas-liquid ratios less than 2.0 Mcf per bbl. Thus, Shaw, Babson, and the late E. N. Merrill mentioned by Babson, provided the prior work mainly used in the appended correlations of vertical flow.

It will be noted that no distinction is made here between gas-lift and natural flow. In the gas-lift range covered by Babson, mist flow and annular flow predominate and no perceptible differences are to be expected. Where foam flow exists, one would be led to expect somewhat steeper gradients for natural

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† Presented at the spring meeting of the Pacific Coast District, Division of Production, Los Angeles, May 1954.
‡ References are at the end of the paper.
flow than for gas-lift with the same total gas-liquid ratios, because for natural flow more of the gas would be in solution, and the ratios are small enough that the gas in solution could be an appreciable part of the total available. In any case, it may only be said that no firm differences between gas-lift and two-phase natural flow have been observed; and the results here presented involving flow are derived from flowing-well data and would therefore tend to represent foam-flow gas requirements conservatively.

The present purposes are to explain flowing and gas-lift well performance in the light of what is now known of vertical flow, and to provide procedures and empirical correlations which have been usefully applied over a period of years in solution of practical problems. It is believed that the graphical procedures suggested are widely adaptable. The gradient data, however, should be used with care and are offered in the hope that they may encourage development of more specific data in forms readily adaptable to field use.

A PRIMARY DISTINCTION

To develop an understanding of the behavior of flowing and gas-lift wells, it is essential first to recognize that there is one set of conditions affecting flow of gas-liquid mixtures into a bore hole, an entirely different set of conditions affecting flow of mixtures from the bottom to the top of the well, and a third set affecting flow through beans at the surface. We may designate the first as "inflow performance," the second as "vertical-lift performance," and the third as "bean performance."

Inflow Performance

Knowledge of individual well inflow performance is a basic necessity in equipping and operating oil wells for maximum profit under any set of imposed conditions.

Rigorous determination of the inflow performance of a well at any state in its producing life would involve:

1. Measurement of the static pressure in the well at the midpoint of the producing interval.
2. Measurement of the mass rate of inflow of each fluid phase corrected to midpoint conditions for each of a series of steady operating pressures measured at the midpoint.

Fortunately, such detailed determinations are seldom necessary; but one or more very complete determinations in a particular field can prove helpful in deciding what short-cuts and approximations are locally practicable.

The liquid inflow performance of a well at any stage in its decline may be defined by its static pressure (in pounds per square inch) and maximum inflow rate when the increment of inflow per unit of pressure or productivity index (PI, measured in barrels per day per pound per square inch) is a constant. The gas-liquid ratio (GLR measured in thousand cubic feet per barrel) may be, for practical purposes, constant. Under such simple conditions the inflow performance can be depicted as shown in Fig. 1. Individual-well inflow-performance trends may be depicted as shown in Fig. 2. This latter type of graph is useful in predicting both the timing and character of lifting changes needed to maintain production and implement the local reservoir policy. The relation between the midpoint pressure and the liquid inflow rate (inflow performance relationship, or IPR, as mentioned later) is not always a straight line as shown in Fig. 1, but may be concave to the origin as shown in Fig. 3. Even if this curvature is marked, it is possible by study of a group of such curves from a given field to develop a locally applicable method of predicting the IPR from the well's static pressure and a single drawdown determination.

Gas-liquid ratio control is a principal factor in development of reservoir policy. Ratios in practice are affected by cumulated withdrawals; and, at any one stage of withdrawal, they are affected by production rates, as has been pointed out by H. J. Sullivan.* Generally, of all factors bearing upon future well performance, the gas-liquid ratio is the least predictable.

*Fig. 1—Diagram of Inflow Performance
Fig. 2—Graph of Individual-well Inflow-performance Trends

There have been instances of gas-oil ratio reduction following a change in the tubing setting depth in flowing wells. However, the practice is not recommended, especially if it involves killing the well with water, inasmuch as the change in tubing depth can have only a very minor effect of the drawdown opposite gas sands for a given liquid rate; and if the water reduces gas production, it is likely, at the same time, to reduce the well’s future oil potential.

Water can be a useful agent in an oil reservoir; but on reaching the well bore, its usual tendency is to minimize flowing life, ultimate recoveries, and total profits. The operator is fortunate when water production can be economically excluded. The type of water-cut curve shown in Fig. 1 generally indicates water influx predominantly from a relatively low-pressure source, and the cut curve in Fig. 3 a predominantly high-pressure source. Cut-cumulative curves such as the one shown in Fig. 2, are of well-known value in estimating future oil recoveries from wet wells.

In selecting the best operating gross rate for an individual wet well, it is sometimes helpful to plot the approximate water IPR from the gross IPR and two or three cuts as indicated in Fig. 4. However, if special tests are necessary for this purpose, it is desirable to remember that temporary use of abnormally high inflow rates can induce a permanent in-

Fig. 4—Procedure for Outlining the Water IPR
crease in water productivity under some circumstances, e.g., if the water shut-off is insecure, or if there is a wide disparity between water and oil viscosities, gentle formation dips, and edge water close to the bore.

Differential depletion is progressive during sustained flowing periods wherever the ratio of lateral permeabilities to vertical permeabilities is large; and interflow through the bore between producing layers takes place during any subsequent periods of shutdown unless a suitable mud is spotted in the producing interval. Thus any water inflow from a relatively high-pressure source tends to seek out and enter the more depleted oil layers during a shutdown period, and with permanent injury in some fields to effective oil permeabilities. After long pe-
periods of flow, a two- or three-week shutdown can cause from 20 to 40 percent permanent reduction of the inflow capacity of a well tapping a depletion-type reservoir even if the water cut is no greater than 5 percent. Thus, differential depletion is a factor requiring close consideration in many fields if the operator's equity in operating wells is to be protected.

Generally, the rate of liquid inflow increases as the operating pressure in a well is reduced, and the absolute maximum liquid inflow would result if zero absolute pressure could be maintained at the bottom of the well. This condition, of course, cannot be attained, and least of all in a flowing well, because a pressure drop in the tubing from the bottom to the top of the well is necessary to sustain vertical flow. A large pressure at the bottom of a well facilitates vertical outflow but discourages lateral inflow. In this sense, the pressure requirements for inflow and those for vertical lift are opposed to one another, and, in particular cases, when an effective compromise can no longer be made by adjustment of controllable factors, flow must cease. For any steady flowing condition, the sum of 1, the effective pressure drop from the drainage radius to the bore, 2, the pressure drop in the vertical column, and 3, the pressure drop across the beam (or orifice) at the surface is substantially equal to the difference between the well's static pressure and the flow-line pressure.

Vertical-lift Performance

All we need know about two-phase vertical flow is how much pressure is required to lift the well liquid at a given rate from a given depth with a given gas-liquid ratio through tubing of a given size. This problem is more complicated than the problem of single-phase flow in surface pipelines because we are dealing with the flow of a gas-liquid mixture, and because the input pressure must be sufficient not only to overcome flow resistance in the pipe and the beam at the surface, but must in addition be sufficient to support the total weight of the compressible mixture in the pipe. In single-phase horizontal flow, the total pressure drop for a given flow rate can be represented as so, many pounds per square inch per thousand feet of length. No such convenient yardstick can be used for vertical two-phase flow because the pressure drop per unit of length is not constant, but increases with depth. For this reason, in proceeding to systematize field information on vertical flow for pressures less than the bubble-point pressure, we find there is a different depth-pressure gradient for each size of pipe, each rate of liquid flow, and each gas-liquid ratio.*

Depth-pressure Gradients

The depth-pressure gradient is the basic unit of two-phase vertical flow, and solution of individual well problems is largely a matter of having available a representative family of gradient curves covering suitable ranges of tubing sizes, rates of liquid flow, and gas-liquid ratios.

We are not concerned here with any detailed analyses of the physical phenomena which cause the pressure gradients observed or derived from practical field information. However, it is of interest to know that a single gradient curve represents a sequence of different types of flow. Thus, starting at the upper end of a gradient like that for 200 bbl per day in 2.875-in. tubing with 1.0 Mcf per bbl gas-liquid ratio, as shown at A in Fig. 5, mist flow will predominate at the lowest pressures, modified progressively by an upwardly moving oil film which clings to the inside surface of the pipe and increases in thickness with depth. This film, combined with mist flow in the center of the pipe, has been described as annular flow. As relative depths increase, the film becomes so thick and wavy that it occasionally bridges across the section, resulting in slug flow. At still greater depths, slug flow merges into foam flow, and this finally merges into single-phase flow at the pressure beyond which all of the gas is in solution.

Fig. 5 illustrates the use of a gradient curve in determining the tubing pressure from the intake pressure, or the intake pressure from the tubing pressure, for a given production rate and ratio for a well of any depth. For instance, as shown at B in Fig. 5, 5,000-ft wells with 2.875-in. tubing producing 200 bbl per day with 1.0 Mcf per bbl will have an intake pressure of about 440 psi if the tubing pressure at the surface is one atmosphere (zero gage pressure), and, as shown at C, they will have an intake pressure of about 1,750 psi if the tubing pressure is 800 psi. Similarly, as shown at D in Fig. 5, an 8,000-ft well for the same conditions having an intake pressure of

* Gradients presumably are also affected by many other factors including liquid surface tension, viscosity and gravity, flowing temperatures, gas gravity, and gas-liquid solubilities. However, there is a reasonably close correspondence between results which have been obtained in the light-oil (25 to 40 API) fields of Long Beach, Santa Fe, Dominguez, Ventura, Canal, and Ten Section, and several foreign fields, without adjusting for such factors. Also, it has not been found necessary to correct gradients for water cuts. However, the gradients are inadequate to predict the effects of emulsions.
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Fig. 5—Use of Gradient Curves

1,390 psi will have a tubing pressure of 200 psi. Thus by using the gradient for the desired production rate and ratio and interpolating when necessary, we may estimate either the tubing pressure or the intake pressure in a well of any depth when one of these pressures is known.

Empirical gradient curves for 2.875-in. tubing are given in Fig. 23 through 27, and similar families of gradient curves for 1.66-, 1.90-, 2.375- and 3.50-in. tubing are given in Fig. 28, 30, 31, 32, and 33. The 2.875-in. gradients are based upon correlation of data with gas-liquid ratios ranging from 0.4 to 2.0 Mcf per bbl from 8,000-ft wells in Ten Section Field, combined with Babson's generalizations in the gas-lift range. Errors attributable to the 2.875-in. curves for 100, 200, 400, and 600 bbl per day should not exceed 15 percent. The gradients for 50 bbl per day in the 2.875-in. size and for 50, 100, 200, 400, and 600 bbl per day in the other sizes are based upon information which is far less complete. However, they are offered in the belief that they reliably indicate the relative characteristics of each size and are not likely to lead to misapplications if conservatively employed. Further, it may only be said that they represent a fair correlation and interpretation of the information readily available.

The Two-phase Vertical-lift Function

Using the process outlined in Fig. 2, and a set of gradient curves, such as those on Fig. 23 through

27, the two-phase function for any particular depth and tubing-outlet pressure may be constructed. For example, confining attention to 8,000-ft wells, 2.875-in. tubing, and zero gage tubing pressure, the function may be represented either in terms of intake pressure and gas-liquid ratio, as shown at A in Fig. 6, in terms of intake pressure and production rate, as shown at B in Fig. 6, or in terms of intake pressure, production rate, and gas-liquid ratio, as shown at C in Fig. 6. All three graphs represent equivalent information: At A is the type of graph used by Babson; the form of illustration B is interesting because the ordinates and abcissae are the same as those for the inflow performance (IPR) of a well, and the two types of data may thus be superimposed. They are considered following in connection with estimates of the duration of flowing life. Several general characteristics of two-phase vertical flow may be observed at C in Fig. 6. In particular, it may be noted that:

1. For any constant gas-liquid ratio there is a rate of flow which requires minimum intake pressure. Also, this rate of flow for minimum pressure and the minimum pressure itself both increase as the gas-liquid ratio is decreased as indicated by curve 1. (These observations are of interest in connection with flowing wells because of the tendency of flowing wells to have a more or less constant gas-liquid ratio at any one time.)

2. For any constant rate of flow, there is a gas-liquid ratio which provides minimum intake pressure. This minimum intake pressure is directly related to the rate of flow, while the gas-liquid ratio for minimum intake pressure is inversely related to the rate of flow as indicated by curve 2. (These observations are of interest in connection with gas-lift which permits control of gas-liquid ratios.)

The form of the two-phase function is largely the result of the interaction of flow resistance and slippage of gas through the oil, the resistance factor being least important when slippage is greatest and vice versa. It is more or less obvious that the column pressure, being the result of the weight of the mixture, is greatest at low gas-liquid ratios. However, it is less obvious that for any gas-liquid ratio and depth there is a rate which requires minimum lifting pressure with lower rates requiring more lifting pressure because of slippage, and higher rates requiring more lifting pressure because of resistance.
Fig. 6—The Two-phase Vertical-lift Function for 2.875-in. Tubing Set at 8,000 Ft
(Tubing Pressure = Zero Psi Gage)
For the reader who finds difficulty with this set of facts, the following explanation may prove helpful:

a. Imagine for this purpose a 2,000-ft length of 2.875-in. API tubing mounted vertically on the face of a precipice in the Rocky Mountains with a wind-swept platform at its upper end where the reader may observe results, and a special-type pump station at its lower end capable of continuously injecting oil of, say, 0.85 gravity and gas with a constant ratio of, say, 1.2 Mcf per bbl.

b. Taking the initial rate as 0.01 bbl per day of oil with the 1.2 Mcf per bbl ratio, the liquid level would appear at the upper platform after about 115 days (2,000 x 0.01 x 172.7 = 115.8). Out of the oil column the observer would see gas bubbling at the rate of about cu in. per sec (1,200 x 0.01 x 1,728 x 60 = 0.24); and the pump at the lower end would be operating at an input pressure approximating the liquid gradient pressure, amounting to 736 psi (2,000 x 0.433 x 0.85 = 736.1). Most of the gas pumped into the tubing during the 115-day period would have slipped out of the column by the time the level of the mixture reached the observation platform.

c. Now, if pumping of the same mixture were maintained at 400 bbl per day, because the liquid alone would fill the pipe in less than 45 min, (2,000 x 1,440 x 400 x 172.7 = 41.7+), there would be very little time for slippage of gas through the oil and the 480 Mcf per day of gas (400 x 1.2 = 480) accompanying the oil would soon produce an oil mist around the top of the pipe, the gas-oil volume ratio at that point being about 213 volumes per volume (480,000/400 x 5.614). The input pressure would be about 150 psi.

d. Last, with an injection rate of 4,000 bbl per day, slippage would be obviated by extreme turbulence and the input pressure, increased by resistance, would be about 230 psi.

Similarly, if we hold the liquid rate constant and increase the gas-liquid ratio, the intake pressure decreases, from a starting point with zero gas when the pressure is the sum of the liquid weight and the liquid flow resistance, to a minimum, and then increases steadily for greater ratios due to increasing resistance accompanying higher fluid velocities.

The observations summarized in Par. 1 and 2 apply in general to two-phase vertical flow from any depth with an eductor of any size or type and any given outlet pressure.

The relative effects of the different tubing sizes are indicated in Fig. 7 (which was constructed from the gradient curves of Fig. 23-28, 30-33). In general, the smaller tubing sizes offer the advantage of lower intake pressures at comparatively low rates of flow, and therefore tend to prolong the flowing life of low gas-liquid ratio wells. The smaller sizes, however, limit rates of flow, especially for the higher gas-liquid ratios.

Annular flow is not treated here. However, it may be mentioned that the poorer an annulus is as a flow section for single-phase flow, the more effective it will be for two-phase flow in minimizing gas slippage and in improving gas utilization in the slippage range as compared with a circular flow string of equal sectional area.

**Two-phase Bean Performance**

"Bean" is the oil-country term for the orifice used on the tubing outlet to control the production rate of a flowing well. Production men are accustomed to
selecting bean sizes for particular wells on a trial-and-error basis and no correlation for two-phase flow through beans has been generally applied.

The following approximation is derived from regularly reported daily individual well production data:

\[
P = \frac{435r^{0.346}B}{S^{1.89}}
\]

where:
- \(P\) = tubing outlet pressure, in psig
- \(r\) = gas-liquid ratio, in Mcf per bbl
- \(B\) = gross liquid, in bbl per day
- \(S\) = bean size, in sixty-fourths of an inch

Approximate solutions for any one of the four variables when the other three are known, may be made by use of Fig. 29. Directions for use of this chart with examples are given on p. 151. The constant (435) used in the formula is based upon Ten Section data with beans of the types shown in Fig. 29, the results of one sampling from the Ten Section Field being shown in Fig. 8.

An error of \(1/4\)\(^{1/2}\) in. in bean size can effect an error of 5 to 20 percent in pressure estimates. In many cases, gas-liquid ratios are reported only to the nearest 50 or 100 cu ft per bbl and are frequently difficult to determine because of fluctuations which occur in many wells. Spot readings of pressure at heading wells are not representative of daily averages. For reasons of this kind, no formula could be expected to maintain a 100 percent correspondence with observed data at individual wells even though it correctly correlated the variables involved.

As an example interpreting the formula, the performance of \(10/64\)-in. beans 1 in. in length is illustrated in Fig. 9. In the type of formula used, it is assumed that actual mixture velocities through the bean exceed the speed of sound, for which condition the downstream, or flow-line, pressure has no effect upon the tubing outlet pressure (i.e., pressure on the upstream side of the bean). Thus, the formula applies for tubing pressures at least 70 percent greater than the line pressure. For tubing pressures less than 70 percent greater than the line pressure, the bean size indicated by the formula will be too small for the given conditions. No study has been made of two-phase bean performance for tubing pressures in the range from zero to 70 percent greater than line pressure. Field men usually try to avoid operation in this range because fluctuations of line pressure affect the well's operation.

**Flowing-well Performance**

Individual well problems in natural flow may be analyzed quite simply by graphical means, a form which has general application being shown in Fig. 10. In this figure, curve A represents the inflow performance of a well with tubing-intake pressures plotted against liquid production rates. The gradient curves B for 2.0 Mcf per bbl gas-liquid ratio were then plotted starting with the known intake pressures for 0, 50, 100, 200, and 400 bbl per day. The intersections of these gradients at the surface establish the tubing pressures which the well will sustain, and the tubing-outlet performance may then be plotted as shown by curve C. The depth vs. pressure diagram of Fig. 10 illustrates the part...
played by gradients in flowing-well performance. However, curve C may be obtained directly from curve A by subtracting the total gradient pressure for each of several rates of flow. Superimposing the performance curve D for a 19/64-in. bean, we conclude that the well should flow at about 96 bbl per day with a tubing pressure of about 850 psi. Considering curves C and D, as shown in Fig. 11, it will be seen that there are possible equilibrium points, 1 and 2. Intersection 1 provides a stable flowing condition because, if a tendency develops to increase the flow rate, the bean imposes more pressure resistance than the well can sustain; and if a tendency develops to reduce the flow rate, the well develops a higher tubing pressure than the bean requires. In each of these cases a temporary displacement of the flowing rate generates a pressure differential which returns the well to its equilibrium-producing condition. Intersection 2 is an unstable equilibrium point because any temporary displacement brings into action a pressure differential which increases the displacement, and causes the well either to flow faster or to die, depending upon the direction of the initial displacement. This limited explanation assumes a constant gas-liquid ratio. Both the tubing outlet curve C and the bean curve D change with each change in the gas-liquid ratio after the manner shown at B in Fig. 12, but for each ratio there is a stable equilibrium point.

The relationship between bean size and production rates is of the type shown at A in Fig. 12. Two similar curves derived from wells where several bean sizes were used over a short period of time (6 months or less) are shown in Fig. 13. Neither of these wells could be expected to maintain steady flow at rates of less than 50 bbl per day, although they both would produce satisfactorily at higher rates. The reason for this limitation lies in the fact that the differential pressure, available to increase production when the rate of flow temporarily drops below the stable equilibrium rate, progressively diminishes as the bean size is reduced below the bean size which provides maximum tubing pressure. Thus, considering the bean-performance intersections with the tubing-pressure curve for 1,600 cu ft per bbl at B in Fig. 12, a 19/64-in. bean provides...
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maximum tubing pressure; and for smaller beans, large differential pressures are available to prevent sustained increases of production rate, but the differential available to prevent decreases of production rate becomes smaller as the bean size is reduced. For a \( \frac{5}{4} \) in. bean, the tubing and bean performance curves nearly coincide and reductions in rate of flow cannot be prevented. If this size of bean were applied to the well represented, the well would "head up and die." Flow rates, below the practical minimum for one tubing size, can only be maintained by use of smaller tubing, or by flowing the well intermittently for short periods at relatively high rates. Needless to say, the most popular procedure in handling wells with allotments too small to support flow with the existing tubing size is to install mechanical lift. Whether or not this is the best procedure depends upon the well's future capabilities as judged from data summarized in the form indicated in Fig. 2.

FLOWING LIFE

If future IPR's estimated from a graph such as Fig. 2 are plotted for successive stages of oil withdrawal as shown in Fig. 14, and curves such as those shown at B in Fig. 6 are superimposed, an estimate can be made of flowing life. A procedure for this purpose was developed by R. J. Woodward.\(^6\)

In Fig. 14, prepared by Mr. Woodward, the IPR's (shown as straight lines on the left side of the figure) and the gas-liquid ratio against cumulative withdrawals (shown at A in the figure) provide the essential well data. A number of curves for the intake pressures necessary to sustain lift with 200 psi tubing pressure for a series of gas-liquid ratios

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\(^6\) Shell Oil Company
Heading Cycle:

1. Because of the bypassing of gas into the annulus, the liquid level is slowly being lowered, annulus oil is being displaced into the tubing.
2. The well is still producing at a low rate and the tubing column is heavy because gas is being diverted into annulus and oil from the annulus is being diverted into the tubing.
3. The weight of the tubing column is being reduced because no further gas can be stored in the annulus. This further reduces the intake pressure, and
4. Allows gas from the annulus to "blow around." For a short time the well is gas-lifted with annulus gas at a high rate, and this reduces the intake pressure to its lowest value. The well gas is NOT being used to best advantage.
5. The extra annulus gas has been dissipated and fluid, because of the low intake pressure, is flowing at a high rate into both the tubing and the annulus. The tubing column is becoming heavier and the outflow rate is diminishing.
6. Fluid is still flowing into the well at a faster rate than it will flow out of the well with the existing intake pressure.
7. The rate of outflow is again in balance with the rate of inflow, and bypassing of gas into the annulus starts repetition of the cycle.

Observations.

This is not an efficient type of flow because it produces a large proportion of the oil with a deficient supply of gas and a small proportion of the oil with an excess supply of gas.

The usual practice of beam ing a well back to a low rate of flow to avoid this type of surging is not efficient, and in many instances results in avoidable reduction of income.

This type of flow is characteristic of the latter part of the flowing life of wells in most areas, but is also characteristic of many relatively new low gas-liquid ratio wells.

Heading action of this kind can be minimized by use of tubing-casing packers, but where packers are not already installed, use of casing-actuated intermitters may be preferable.

Fig. 15—Unsteady Natural Flow
**Heading Cycle:**

1. At the start of the flowing period, the tubing is opened by the rising casing pressure which actuates the motor valve. The column of gas which has collected in the upper part of the tubing is produced, and the consequent reduction of pressure ensures flow of the fluid mixture in the tubing below this gas column.

2. The tubing pressure trends downward while fluid is being displaced out of the annulus, and then

3. Rises as annulus gas starts to break around the foot of the tubing.

4. When the casing pressure reaches the predetermined minimum, the motor valve closes the tubing outlet, but flow into the well continues with very little decrease in rate, both gas and liquid flowing into the annulus. Tubing pressures continue to rise. The casing pressure, which is directly related to the amount of gas stored in the annulus, also increases in response to gas and liquid entering the well. When the casing pressure reaches the predetermined maximum, repetition of the cycle is started by opening of the motor valve.

**Observations:**

By regularizing flow, casing-actuated intermitters can be used to increase the rate of flow and extend the flowing life of wells when they reach the heading stage.

Intermitters are not to be recommended for wells which will produce more on the pump, but they are recommendable:

a. To increase the rate of flow of wells which have been beamed back to avoid heading.

b. To regularize and increase the flow of new low-ratio wells until increase of gas ratios may permit steady flow at desired rates.

Intermitters have been used to flow wells which would not flow without an intermitter, wells with water cuts exceeding 50 percent and wells at rates exceeding 500 bbl per day. Intermitters have been misapplied, and mostly by inexpert selection of beam size and casing-pressure ranges. The beam should preferably be as large as necessary to ensure a continuous drop of casing pressure during the on-period (1 to end of 3) and no larger. The casing-pressure range must be large enough to ensure a flow of gas around the foot of the tubing, signalled by a steady buildup in tubing pressure. A longer range is unnecessary and often undesirable.

**Fig. 16—Intermitter Control of Natural Flow**
were superimposed over the IPR lines and the well's flowing progress was interpolated using the gas-liquid ratio data given. When the well's progress curve becomes tangent to the IPR, flow must cease. By constructing similar graphs for other tubing sizes, it was concluded that this well would flow 120,000 bbl in 415 days with use of 3.5-in. tubing; 135,000 bbl in 505 days with 2.875-in. tubing; and 265,000 bbl in 1,370 days with 2.375-in. tubing. Any serious errors in tubing-size selection can be avoided by applications of this procedure.

In connection with flowing life, it may be mentioned that observed rates of decline during natural flow are usually unreliable as indices of the decline of well inflow capacities. Consequently, misapplications can result from assuming that flowing decline is representative of the decline to be expected on mechanical lift. The reason for this lies in the fact that flowing is a high-rate lifting method and requires greater lifting pressures as rates are reduced. Examples can easily be drawn from practice. However, in the hypothetical case of Fig. 14, it will be seen that the well starts out flowing about 57 percent (625×100/1,100) of its initial maximum-rate capacity, and at the end of its flowing life, it is only producing about 14 percent (75 x 100/540) of its residual maximum-rate capacity.

UNSTEADY FLOW

A working knowledge of unsteady flow is a necessary tool in maintaining desired production rates and in avoiding unnecessary stoppages, particularly in the latter stages of flowing life.

There are two principal sources of unsteady flow: 1, segregation of free gas from liquid in the rising fluid column, and 2, segregation of free gas from liquid at the tubing intake.

Formation heading, which is evident in La Paz Field, Venezuela, may be excluded from usual consideration inasmuch as it cannot occur unless the well is tapping a fissured or cavernous reservoir.

Heading of the first type is observable even in settled pumping wells operating with low-liquid volumetric-pump efficiencies and is a relatively unimportant phenomenon. It causes relatively small, and often irregular, pressure changes of short cyclical duration and has little effect on the continuity of production except in very weak flowing wells. It may accentuate unsteadiness of the second type. Also, its presence makes tubing pressures inferior to casing pressures both as indices of operation, and as means of flow control.

Heading of the second type (sometimes called "annulus heading") occurs when 1, bubbles of free gas at the intake are big enough to escape entrainment with the liquid entering the intake, and 2, the gas-liquid ratio is materially smaller than the gas-lift optimum for the average producing rate of the well. Fig. 15 provides diagrams illustrating heading of this type, and Fig. 16 illustrates the control function of an intermitter in this connection.

This type of intermitting does produce oil from the well head by "jerks," but it regularizes inflow, and with suitable adjustment, it reduces the range of velocities through the liner screen as compared with unregulated heading. A normally closed motor valve is preferable for operating a well at a low percentage of its full flowing capacity and a normally open valve should be used for maximum-rate operation.

Casing-tubing packers obviate annulus heading if installed at the intake, but do not serve the function of an intermitter in regularizing production at rates below the minimum stable-flow rate; and if not installed when the well is completed, the danger of damaging the well by killing it with mud or water to install a packer may make alternative use of an intermitter more attractive. Incidentally, the only function of a packer in this case is to guide bubbles into the tubing, which fact may suggest new forms which are equally effective and still permit ready means of circulating to kill the well, if necessary, without moving the tubing.

CASING AND TUBING PRESSURES

When gas bubbles are large enough to escape entrainment with liquid entering the tubing, the annulus fills with gas and the casing pressure becomes a sensitive indicator of flowing performance. An empirical formula for estimating intake pressures from casing pressures is given in Fig. 17. Bubble sizes at the intake, of course, cannot be measured directly. However, an engineer armed with simultaneous measurements of casing and intake pressures can easily determine whether or not the casing pressures of the wells in his area are useful in estimating intake pressures. Gas gradients are most likely to exist when gas-liquid ratios are on the high side and productivities are small. Two-phase gradients are helpful in this connection, but are often less accurate than casing-pressure data because they depend upon gas-liquid ratios which are less reliable than pressure measurements.
FLOWING AND GAS-LIFT WELL PERFORMANCE

In many fields the IPR of a well may be estimated from knowledge of its static pressure plus a representative casing pressure and the corresponding liquid-production rate, as indicated in Fig. 18. For heading wells, the average casing pressure may be used. Estimates of this type are in error on the conservative side if the annulus contains liquid (i.e., the true IPR will be larger than the estimated IPR). Thus, if casing pressures and static pressures have been carefully measured and recorded, they can often be used to outline IPR trends in terms of withdrawals.

Generally, tubing and casing pressures merit attention both from engineers and operating personnel, and there is much to be said in favor of accurate reporting and control of bean sizes.

Range-indicating pressure gages are beginning to be usefully applied, the thought being that flowing wells do not require gaging or other individual attention except when a change occurs in the normal range of variation of their tubing and casing pressures. Range readings are often conclusive as indices for operating control, and spot readings are not conclusive.

RESTARTING NATURAL FLOW

Flowing wells are not improved by periods of shutdown; and when they die, they are candidates for immediate attention. Even though flowing is no longer the optimum method, it is sometimes desirable to restart a well as a protective measure until final-lift equipment is ready for operation.

Strong high-pressure high-productivity wells restart when the flow valve is opened; and at the other end of the scale, there are weak wells which can only be restarted by a procedure tailored to the requirements of the individual well and applied without unnecessary loss of time.

In connection with restarting, the following facts are often significant:

1. The gas-liquid ratio typical of the well may require two or three days of operation for full development after restarting because, under shutdown conditions, liquid produced into the well bore frequently invades the more active gas-producing layers and temporarily reduces effective gas permeabilities.

2. For wells without tubing-casing packers, it is usually necessary to fill the annulus with gas at the desired intake pressure before stable flow can be re-established.

3. If the well dies as a result of heading action, delay may diminish the possibility of successful restarting. Also, in critical cases, use of smaller tubing or use of a casing pressure-actuated intermitter may be necessary if it is desired to prolong the well’s flowing life.

Swabbing is definitely inferior to use of a gas compressor for difficult restarting jobs because, with swabbing, the well ordinarily restarts with a considerable column of liquid still remaining in the annulus; and by the time the production crew has moved to another location, bypassing of gas past the intake loads the tubing with a heavy mixture from the annulus and the well dies. Incidentally, as a well declines, reduction of the bean size is necessary to maintain stable flow. However, changes
must be made in small increments at weak wells because for each increase in intake pressure an easily computed extra quantity of gas must be stored in the annulus before the well's full gas-liquid ratio can be effective in the tubing for lifting at the lower rate. Ignorance of this fact and lack of a readily available starting compressor result in premature relinquishment of natural flow in many cases.

**GAS-LIFT APPLICATIONS**

It is still true that no one method of lift will provide optimum results in all wells, and due process of rating wells and methods will always be desirable to maintain the profit margins essential in meeting demands for oil.

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**Fig. 19—Illustration of the Procedure Used for Maximum-rate Gas-lift Estimates**

Gas lift is primarily a high-rate method and can be a final-lift method in wells tapping strong water-drive reservoirs, as illustrated by experience in some Louisiana fields. It can have useful applications when allotted rates are materially smaller than inflow capacities. Use of gas as a means of liquid lift is always attended by imposition of some back pressure against the formation, even when packers are used, and even when standing valves and concentric or eccentric induction tubes are used, but it must also be observed that formation back pressures are often unavoidable with the other forms of lift and especially when gas accompanies the oil produced. For this reason gas lift can be expected to find applications where the bore of the well is so small as to prevent effective gas-anchor action. It is also applicable when depth limits the relative capacities of other methods.

To estimate the maximum-rate gas-lift possibilities of a well with a given IPR at a given tubing pressure, it is only necessary to plot the intake pressure for each of a series of rates. In each case, start on the optimum gradient (the one gradient in each graph marked with an arrow in Fig. 23-28, 30-33) at the given tubing pressure, measure down from this point the depth of the well, and read the intake pressure. As shown in Fig. 19, the resulting curve, A, outlines the highest-rate gas lift possible with the given tubing size, tubing pressure, and depth; and the intersection of this curve with the IPR gives the highest rate and lowest intake pressure attainable under the given conditions in the particular well. By plotting the gas-liquid ratio for each gradient, an estimate, B, of the required total gas-liquid ratio is obtained from which the well's gas-liquid...
ratio is subtracted to obtain the net gas-liquid ratio needed. Use of a higher or lower total gas-liquid ratio will increase the intake pressure and reduce the liquid-production rate. Both maximum-rate curves, such as A in Fig. 19, and optimum gas-liquid ratio curves such as the one shown in the figure, may be considered to be straight lines on log-log paper when extrapolations are necessary, as shown in Fig. 20. This observation does not hold for other gradients and their ratios; and, of course, any extrapolation of empirical data must be made advisedly.

Fig. 21 illustrates some of the many gas-lift and flow alternatives adaptable to a given well, and is introduced as an illustration of the type of graphical analysis which may be used. Such a well with a full string of 2.875-in. tubing would be nearing the end of its flowing life, as indicated by the smaller of the two tubing-pressure curves in graph C. It would flow strongly with use of a full string of 1.66-in. tubing using a compressor for starting. Its maximum-rate gas-lift performance with a full string of each of three sizes is also shown in graph C and corresponding gas requirements are shown in graph D. The input casing pressure for gas lift from 5,000 ft would be between the intake pressure and the static gas-gradient pressure shown. The well’s maximum-rate gas-lift performance with a 1,000-, 2,000-, 3,000-, or 4,000-ft string of 1.66-in. tubing inside 2.875-in. tubing is shown in graph B. Graph A shows 2.875-in. gradients for 0.4 Mcf per bbl.

Solution of well problems using combination strings can be made by adding gradients, using the same ratio for natural flow or gas lift through the different sizes, and using the same pressure at the depth at which a juncture between sizes takes place.

Any adequate discussion of flow valves would be beyond the intended scope of this paper. Flow valves have contributed greatly to the practical utility of gas lift. They are indispensable for starting against the high well pressures and for automatic restarting. Intermittent types with standing valves have been used for maintaining higher rates of flow than those possible with straight gas lift in particular wells. The predictability of gas lift with flow valves is not solely the responsibility of the valve manufacturer, but depends greatly upon the deference the operator has paid to determining well data of the type indicated in Fig. 2. However, as better gradient data become available, improvements may be made in valve spacing, and both installation costs and the proportion of total horsepower needed for starting can be reduced. Incidentally, it seems likely that, with use of improved gradient data, a demand will develop for accurate determination of pressure losses through flow valves of the different types; and the exemplary data provided by one manufacturer for flow of gas through surface beans do not necessarily apply without modification to other types of orifices used in a tubing string.

In order to compare gas lift with other methods of lift in particular cases, the oil-country engineer

\[ H_p = P_1 V_1 \left( \frac{k}{k-1} \left[ \frac{P_2}{P_1} \right]^{\frac{k-1}{k}} - 1 \right) \]

Taking \( k = 1.25 \) for wet gas, this formula may be written:

\[ H_p = 0.223 M \left( \frac{P_2}{P_1} \right)^{0.2} - 1 \]

wherein \( M = \) Mcf per day at 14.7 psi. It is here suggested that this is the horsepower upon which quotations should be based with the given 1, pressure ratio; 2, input gas temperature; and 3, input pressure, and may be from 20 to 40 percent less than manufacturer's brake-horsepower ratings depending upon the deviation from Boyle's law, the auxiliaries used, and the overall plant efficiency attained.

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The gas horsepower required by the gas-lift user is:

Fig. 22—Chart Suggested for Estimating Gas-horsepower Requirements for Gas Lifting
stands in need of a ready means of estimating horsepower requirements. Possibly a formula of the type given in Fig. 22 can be adapted to this purpose. Although manufacturers may regard this suggestion as an over-simplification, they also may be inclined to agree that some simplification would serve to promote compressor sales for gas lift in competition with other lifting means. The temperature of power gas, because of its low specific heat, is usually controlled by well temperatures at points of application, and usually the gas-rate requirement is estimated at standard conditions.

CONCLUSION

The material presented here is offered as an interim report on a phase of production operations deserving wider attention than it has been accorded in the past. It is desired to thank the Shell Oil Company for making the presentation possible, and particularly since this outline was completed during the writer's stay in their California area.

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9 Sullivan, R. J. Gas-oil Ratio Control in Flowing Wells, Drilling and Production Practice, 103 (1937).

DISCUSSION

R. C. Sheldon (The Ohio Oil Company, Los Angeles) (written): The author has prepared a very useful tool for the solution of problems relative to flow of oil, gas, and water in a tubing string. In so doing, he has assembled many pertinent facts, as well as helpful graphs. These should prove especially helpful to the engineer who is confronted with the problem of design for a tubing string in a flowing or gas-lift well.

The oil industry is accustomed to thinking of conservation in terms of barrels of liquids or material recovered, yet often fails to realize that the conservation of energy is equally important. The conservation of energy leads to a conservation of petroleum and increased recovery. Therefore, the conservation of nature's energy in producing oil becomes as important as any other phase of conservation or economies.

The author briefly mentions the use of the "inflow performance relationship," or IPH, which corresponds to the well-known "productivity index" or PI. In actual practice, the mass rate of inflow of each phase is usually replaced by the PI. This is a good approximation where the water cut is not large (less than 25 percent) or the gas-oil ratio is not excessive. What constitutes an excessive ratio for calculations in which PI is substituted depends upon temperature, pressure, and fluid characteristics. Certainly, PI is meaningless for calculations involving retrograde condensate wells which make significant volumes of water.

One question which occurred to me is: What effect has viscosity on the relationships developed? It is realized the Ten Section Field crude has low viscosity, in the range of 0.5 to 5 centipoises within the flow string, depending upon temperature and composition. I should like to ask the author if he has any data showing the effect of viscosity on the charts prepared. What effect does viscosity have on the equation for the bean size—pressure relation? Would the rapid change of slope in the viscosity—pressure curve at lower pressures explain the sensitivity of flow volume to changes in bean size at these pressures? Perhaps the omission of a viscosity function in the bean size—pressure equation would explain the author's point that the equation cannot be used at pressures less than 70 percent greater than line pressures. It will be recognized that this is the pressure range where bean size is most critical—a slight error often results in killing the well.

The author states "... rates of decline during natural flow are usually unreliable as indices of the decline of well inflow capacities." This difficulty may be overcome by observing the decline in potential or productive capacity with time.

Students of this problem will agree with the author that this is "a phase of production operations deserving wider attention than it has been accorded in the past." This paper represents a praiseworthy contribution to the industry.
Mr. Gilbert: The IPR and the PI are not equivalents. The IPR, as used in this paper, is the relationship between intake pressure and liquid inflow rate. The PI is the first differential of the IPR in the special case when the latter is a straight line, or is so nearly straight that its curvature may be ignored.

Very roughly, depth-pressure gradients some 15 percent heavier than those in the paper were found necessary for gas-oil ratios up to 1 Mcf per bbl in one field; but in this case the oil viscosity is at least 100 times greater than that of Ten Section crude. It is believed that viscosity effects on flow through beans will prove very minor because of the existence of intense turbulence. There is a well-known formula, available in any standard summary of flow of gases through nozzles, which may be shown as follows:

\[
\frac{p_1}{p_0} = \left( \frac{k+1}{2} \right)^{k-1}
\]

\( k \) being the adiabatic constant, and \( p_1/p_0 \), the minimum ratio for which flow through nozzles is unaffected by \( p_0 \), the downstream pressure. If \( k \) equals 1.25, the critical ratio is about 1.8, compared with 1.7 used in the report. Thus, suggested use of upstream pressures exceeding the downstream pressures by at least 70 percent is based upon observation of field data and rough consideration of critical ratios (values of \( k \) for oil-laden gas were not determined).

The decline of the production rate of a flowing well is greater than the decline of the well’s inflow capacity, and the disparity increases as flow continues. As Mr. Sheldon points out, it is preferable to follow the well’s inflow capacity, which may be plotted in terms of time, or, better still, in terms of oil withdrawals, as indicated by curves 1 and 2 of Fig. 2.

T. H. Acres (Sunray Oil Corp., Los Angeles) (written): This paper is an excellent analysis and presentation of the factors affecting the behavior of flowing and gas-lift wells. It is the first treatment I have seen that recognizes no distinction between gas lift and natural flow; and, by so doing, it enables one to better understand why natural flow ceases and how, by gas lifting, the energy necessary for the well to flow is augmented. The graphical methods and gradient data presented provide means of predicting when the flowing life will end and also provide means of calculating pressures and volumes of gas necessary for optimum gas-lift operation.

The author points out that the gradient curves should be used with care. These are apparently the result of the correlation of data from many tests in flowing and gas-lift wells modified and extended with information of other authors. Whether they are completely reliable or not, they certainly provide a guide as to the magnitude of pressures and volumes of gas required to lift oil. They further provide a convenient pattern to an operator or engineer for accumulating and presenting the results of his own well tests.

I have several questions that I should like to ask Mr. Gilbert.

1. In Fig. 2—Individual Well Inflow Performance Trend, was the productivity index omitted intentionally?

2. It is stated that flowing wells are not improved by periods of shutdown. Where restarting is not a problem and the well is clean, do you believe some damage may result?

3. In this study, the location of the tubing intake with respect to the perforations must have had to be considered many times. Was there any general conclusion indicated as to the optimum tubing location, i.e., at the bottom of the perforations, top of the perforations, or at some point above?

The author is to be commended for an excellent paper. I believe he has had much of this data for some time, and I am glad his company provided the time for him to assemble it.

Mr. Gilbert: Answering Mr. Acres’ questions:

1. Yes, the PI was intentionally omitted from Fig. 2 in recognition of the fact that IPR’s frequently are curved. However, some engineers may prefer to plot the PI instead of the maximum inflow rate (curve 2) if the well’s IPR may be taken to be a straight line.

2. Yes, there are some possibilities that damage may result in shutting down even a clean well which may be restarted easily. The dangers for short periods of shutdown are usually negligible. However, incipient casing leaks may become active under shutdown conditions (leaks, incidentally, which were sealed off when the casing was tested with mud in the well). Also, under shutdown conditions interflow will occur in long perforated
lengths, with some degradation of potential recovery. These are factors best judged under local conditions.

3. In general, whenever tubing-flow gradients are lighter than gradients in the liner and casing for the same rates, it is preferable to set the tubing as low as is consistent with safety, because the well will flow longer and at higher rates than would be the obtainable with a shallower setting. However, in clean wells with undersaturated crude there is no special point in setting the tubing below the depth where all the gas remains in solution over the full range of desired operating rates.

It is desired to thank Mr. Sheldon and Mr. Acres for their comments.

E.N. Kemler (University of Minnesota, Minneapolis) (written): * Flowing-well performance has not been given the attention which its importance deserves. This is indicated in part by the very meager bibliography included in connection with Mr. Gilbert's paper. Development of better understanding of reservoir performance, together with more recent basic investigations on multiphase flow should make it possible to arrive at a more rational approach to the study of flowing wells. The low cost of production by flowing, together with the advantages of postponing artificial lift as long as possible to permit more accurate evaluation of requirements and capacity of pumping equipment as well as postponement of the accompanying investment, would all contribute to making studies which would prolong flowing life most desirable. Mr. Gilbert's paper is an outstanding contribution to this field and should lead to further studies relating to a rational approach to the study of flowing wells. Tubing and choke installations in flowing wells are deserving of the same consideration with respect to design as that given to design of sucker-rod strings. It should be expected that use of tapered tubing strings, for example, would give better flow conditions than a uniform string.

This paper represents an outstanding contribution to the literature of flowing-well performance. It should contribute to further development in this long-neglected area.

Mr. Gilbert: I wish to thank Dr. Kemler for his kind comments. If natural flow is in a sense the “orphan child” among lifting methods, there may be some significance in the fact that flowing requires very little special equipment and consequently has lacked the extra stimulus of engineering attention accorded by the supply industry to other methods of lift.

Diminishment of well IPR's, and change of gas-liquid ratios in terms of withdrawal, are factors tending to limit the practical utility of tapered strings. However, insertion of a length of smaller tubing inside 3.5- or 2.875-in. tubing will frequently serve to extend natural-flow production of an allotted rate.

The methods of Poettmann and Carpenter are proving valuable in developing improved depth-pressure data in readily usable form, although some difficulty has been experienced with extensions into the pressure range below say 500-400 psi. Also, the analysis of two-phase flow through beams (chokes) given in the paper doubtless can be improved.

In the interests of the oil industry, it is to be hoped that reference material concerning the dynamics and economics of natural flow will be considerably augmented over the next decade.

E.C. Babson (Union Oil Co. of California, Calgary, Alberta, Canada) (written): * As one who has had a little experience with the empirical approach to gas-lift problems, I am impressed by the investigation which is summarized in Mr. Gilbert's paper. This paper carries the empirical analysis of gas-lift performance far beyond any previous work, and I believe it may well prove to be the definitive work on the subject. It is probable that further refinements and extensions of correlations can be made, but the paper covers almost completely the principles involved in applying these data to practical production problems.

Mr. Gilbert: I value highly both Mr. Babson's opinion of the paper and the part his earlier work played in making it possible.

*Prepared following presentation of the paper.
Fig. 23—Approximate Depth-pressure Gradients for 2.875-in. Tubing
Fig. 24—Approximate Depth-pressure Gradients for 2.875-in. Tubing
Fig. 25—Approximate Depth-pressure Gradients for 2.875-in. Tubing
Fig. 26—Approximate Depth-pressure Gradients for 2.875-in. Tubing
Fig. 27—Approximate Depth-pressure Gradients for 2.875-in. Tubing
Fig. 28—Approximate Depth-pressure Gradients for 1.66-in. Tubing at Various Production Rates
USE OF BEAN-PERFORMANCE CHART

A graphical means of estimating the bean performance is given in Fig. 29. Four variables are considered, and when three of these variables are known, the fourth may be estimated. In construction, Part I of the chart represents the performance of a \( \frac{15}{64} \)-in. bean and Part II is simply a means of correcting results for other bean sizes. In solving for any one of the four variables, enter Part I if both the barrels per day and the gas-liquid ratio are known; or enter Part II of the chart if the tubing pressure and bean size are known. The further procedure in solving for each variable may be best explained by examples.

1. **Estimate Gas-liquid Ratio or the Gas Rate**
   Suppose we have a well equipped with a \( \frac{15}{64} \)-in. bean operating with a tubing pressure of 720 psi at 200 bbl per day. No differential recording meter has been installed and an estimate of the gas production is desired.
   
   **Solution:** First find in Part II of the chart, the intersection of the line for the 15 bean at 720 psi; go vertically to the slanting 10-bean line and then horizontally to the vertical 200 bbl per day line in Part I. At this point the gas-liquid ratio is about 1.8 Mcf per bbl, from which the total gas is 360 Mcf per day (200 \( \times \) 1.8).

2. **Estimate Production Rate**
   After a bean change, a new well which showed a ratio of 1,400 cu ft per bbl on the previous gage, is flowing through a 40 bean with 750 psi tubing pressure. What is the probable production rate?
   
   **Solution:** Enter Part II at the intersection of the 40-bean and 750-psi lines and go vertically to the 10 line; then go horizontally to 1.4 Mcf per bbl—the estimated production rate being found to be 1,530 bbl per day.

3. **Estimate Tubing Pressure**
   Establish the performance of a 13 bean for 0.8 Mcf per bbl.
   
   **Solution:** Since the formula indicates that there is a straight-line relationship between tubing pressure and barrels per day, only one point need be established. Thus, going horizontally from the intersection in Part I of the 0.8 ratio and, say, 200 bbl per day, to the 10-bean line in Part II and thence vertically to the 13-bean line, the pressure is found to be 605 psi and for any production rate with the 13 bean and 0.8 ratio, the tubing pressure in psi is equal to the barrels per day multiplied by \( 605/200 \) or 3.03.

4. **Estimate Bean Size**
   A well has been operating for an extended period at 200 bbl per day and 4.0 Mcf per bbl ratio. It is desired to reduce the rate to 100 bbl per day and the tubing outlet performance curve indicates that the tubing pressure at this rate will be 1,800 psi. What size bean should be used?
   
   **Solution:** Enter Part I and go horizontally from the intersection of the 100 bbl per day and 4.0 ratio lines to the 10-bean line in Part II and thence vertically to the horizontal 1,800-psi line. An \( \frac{15}{64} \)-in. bean should be used.
Fig. 29—Bean-performance Chart
Fig. 30—Approximate Depth-pressure Gradients for 1.90-in. Tubing at Various Production Rates.

FLOWING AND GAS-LIFT WELL PERFORMANCE
Fig. 31—Approximate depth-pressure gradients for 1.95-in. and 2.375-in. tubing at various production rates.
Fig. 32.—Approximate depth-pressure gradients for 2.375-in. and 3.5-in. tubing at various production rates.
Fig. 33—Approximate Depth-pressure Gradients for 3.5-in. Tubing at Various Production Rates