Optimum Oil Production With Intermittent Gas Lift

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Intermittent gas lift is a cyclic operation where the well-bore fluids are produced in individual piston-type slugs. Efficient and effective operations depend on proper gas lift installation design and a concerted surveillance by all operations personnel.

DESIGN ORIGIN

This design was originated in Venezuela in a field where the reservoir was to be depleted at a maximum rate to give the quickest results in analyzing test spacing and pressure principles in order to determine the merit of the design. The results pointed toward a definite trend whereby, if the valve spacing and pressure setting were controlled within specified limits, a maximum production rate would result with minimum gas usage and an excellent chance to lift the well down within reasonable physical capabilities.

DESIGN THEORY AND TECHNIQUE

By definition, tubing pressure (P_t), at a given valve depth will be expressed in terms of available lift pressure (P_c) at that valve. If the spacing of valves can be calculated with regard

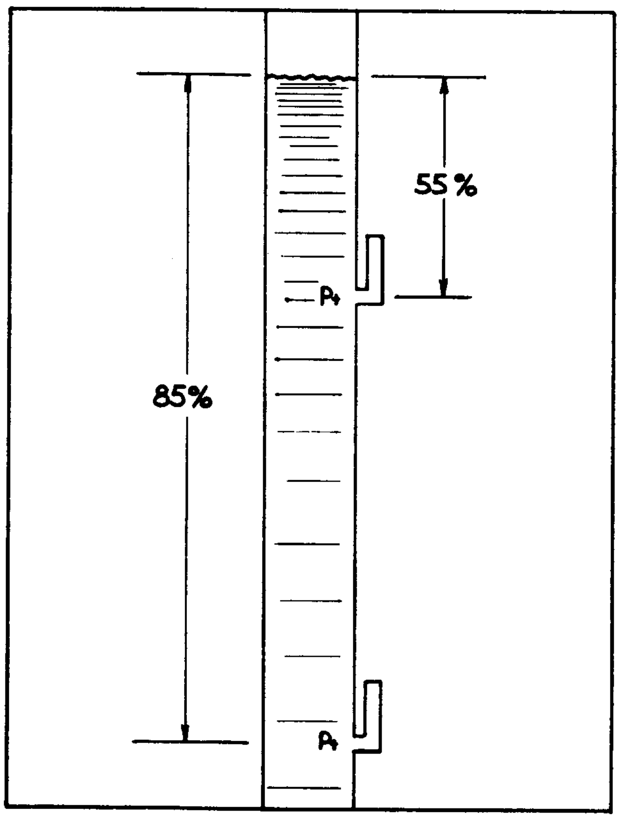

FIGURE 1

Operating

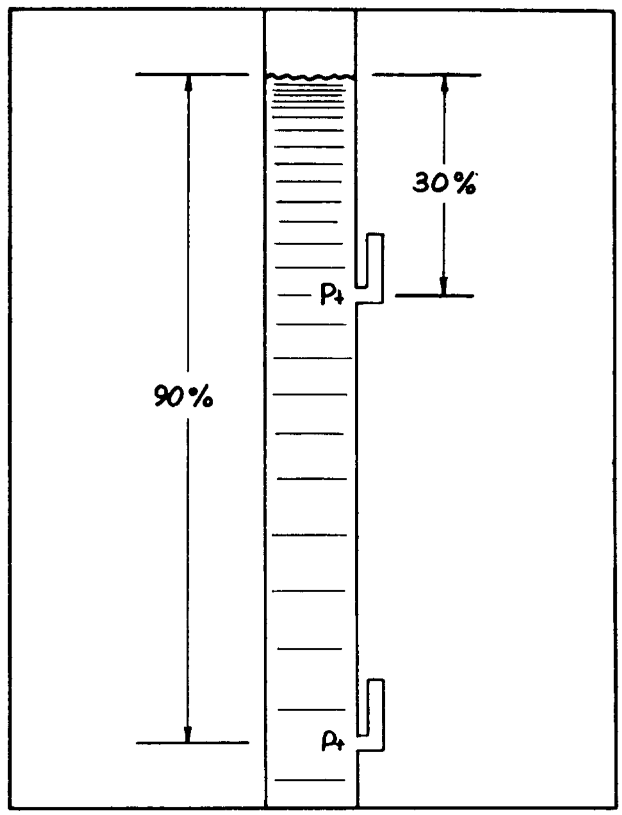

FIGURE 2

Unloading

to static fluid gradient (G_s), maximum and minimum tubing pressures can be expressed for each valve. It would be proper to express this family of maximum and minimum tubing pressures in terms to fit the many available operating pressures as a per cent valve loading rather than specific pressures. Therefore, the tubing pressure at any valve will be expressed as that per cent of lifting pressure available, or per cent loading $= P_t / P_c$. By actual application the maximum and minimum per cent loading was found to be 85 per cent and 55 per cent, respectively. These percentages are used in the productive zone of the well, which is below the static fluid level. The limits for unloading purposes are 90 per cent and 30 per cent. Figure 1 illustrates operating spacing and Fig. 2 illustrates unloading spacing. It is now possible to construct a nomograph by formal mathematical procedure with three pertinent variables: (1) Available lift pressure (P_o), (2) Wellhead back-pressure (P_{wh}) and (3) Static fluid gradient (G_s).

If a given set of valves can be graphically spaced in the production string along with graphically-obtained dome pressure selected to give the valves the required maximum and minimum loading, the intermittent lift operation must comply with optimum results. Figure 3 illustrates the nomograph for valve spacing. It must be remembered that for a given minimum valve loading, a given graph must be used. If other minimum loadings for increased spacings are desired, the same mathematical procedure should be followed.

DISTINGUISHING BETWEEN OPERATING AND UNLOADING SPACINGS

Maximum possible production rates from the bottom unloading valve at various operating

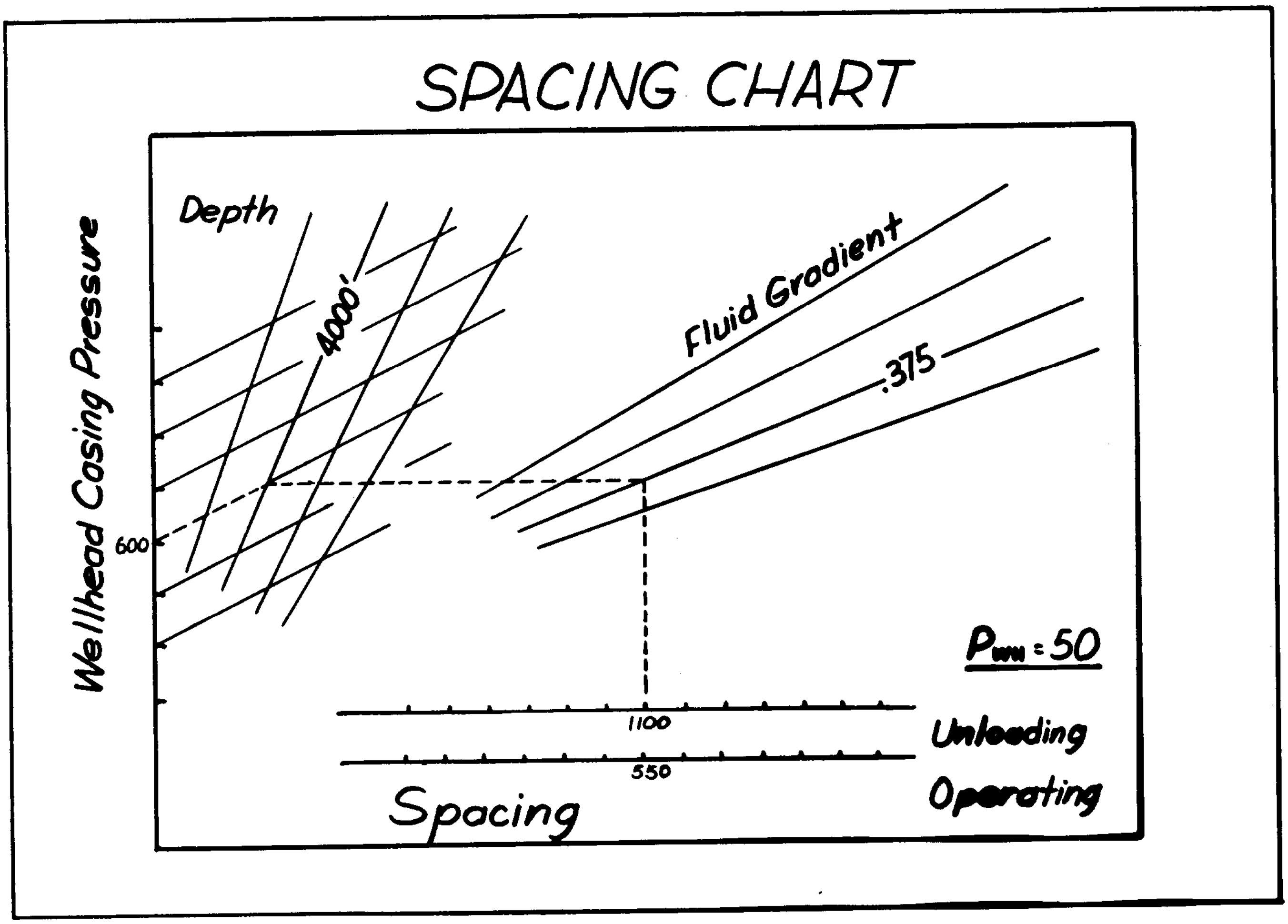

FIGURE 3

pressures were determined experimentally. By plotting these maximum possible rates against actual well capabilities, a maximum unloading depth may be determined. This is illustrated in Fig. 4. It should be pointed out that unloading spacing is used to give greater valve spacing in the non-producing zone of the well to minimize valve usage.

FIELD APPLICATIONS

The gas lift valve spacings are not affected by tubing size as proven by an actual field test where a particular gas lift design was used to produce a well equipped with 2-in. tubing at a maximum rate of 278 BOPD. The well was pulled and 2-1/2-in. tubing was installed with the identical gas lift valve design and the well produced at a maximum rate of 370 BOPD. This illustrates that tubing size is a volumetric function only and does not enter into the design requirements.

PRACTICAL HINTS FOR OPERATIONS

Although proper gas lift design is the basis for any good intermittent gas lift operation, it is essential that field personnel have a working knowledge of gas cost and usage and well operation. A simple trial and error testing procedure that can be used by field personnel to help determine when a well is producing at the maximum fluid rate for the minimum required lift gas usage, is a plot of producing rate versus volume of gas injected per day (see Fig. 5). For any given well condition, increasing the volume of injection gas can be beneficial to increased producing rate only to a point; this point is considered the optimum operating condition for the given well. Whenever the volume of injection gas is increased beyond this optimum condition, the lifting cost per barrel of produced oil is increased without increased production. Injection volumes

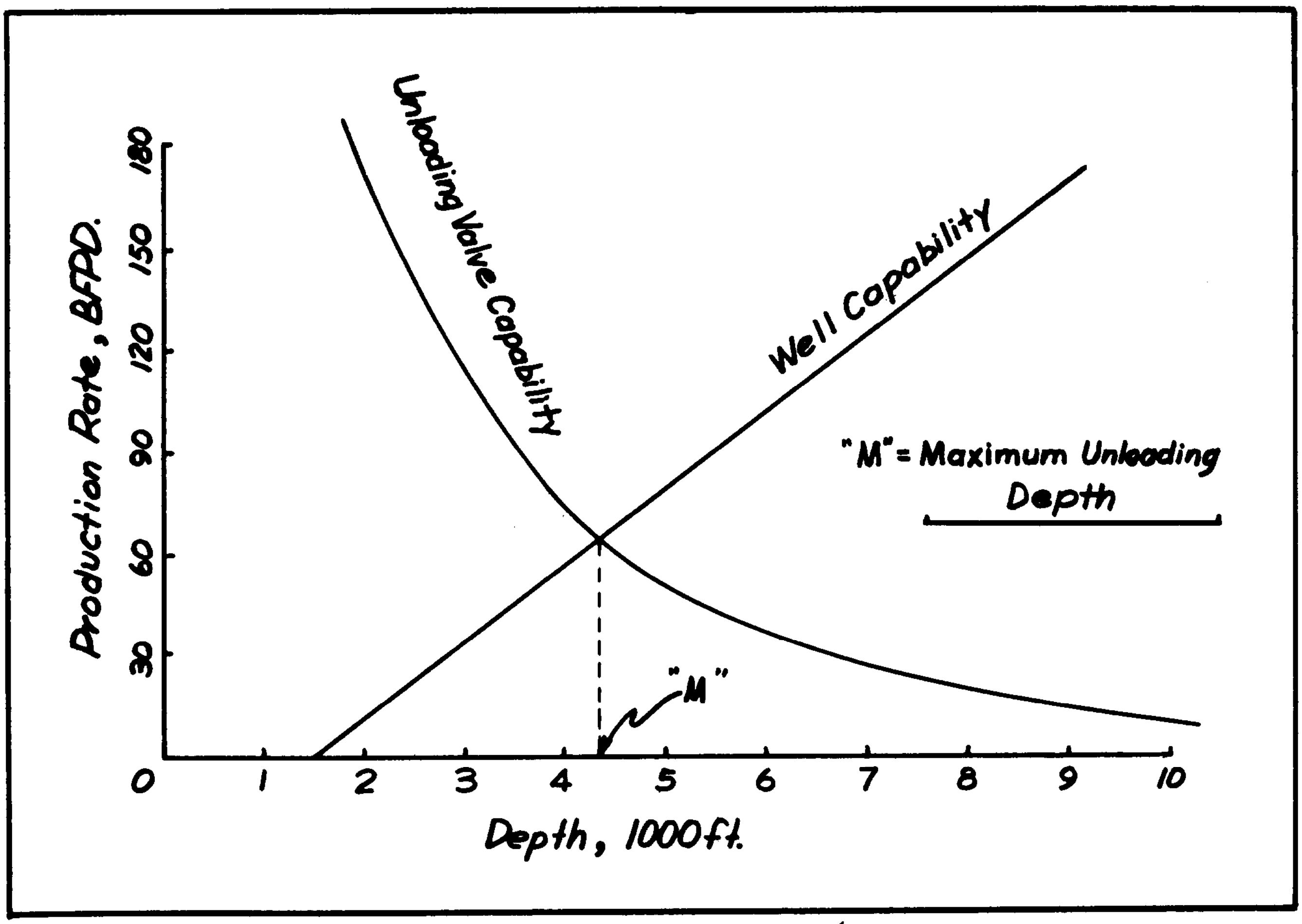

FIGURE 4

can be increased to such magnitude that the actual fluid produced is decreased. Therefore, the optimum operating condition is reached when sufficient volumes of injection gas are used to supply the required energy to lift each slug of fluid to the surface without applying excessive back-pressure on the formation and preventing inflow of fluids to the well-bore.

20 to 1000 pounds per square inch may be 5 cents per 1000 cubic feet (MCF). Therefore, if 1000 cubic feet of injected gas were used to lift a barrel of oil, the cost would be 5 cents per barrel. If the optimum lift gas requirement were 1000 cubic feet per barrel, but 5000 cubic feet per barrel were used, the lifting cost per barrel would be 20 cents per barrel more than that actually required.

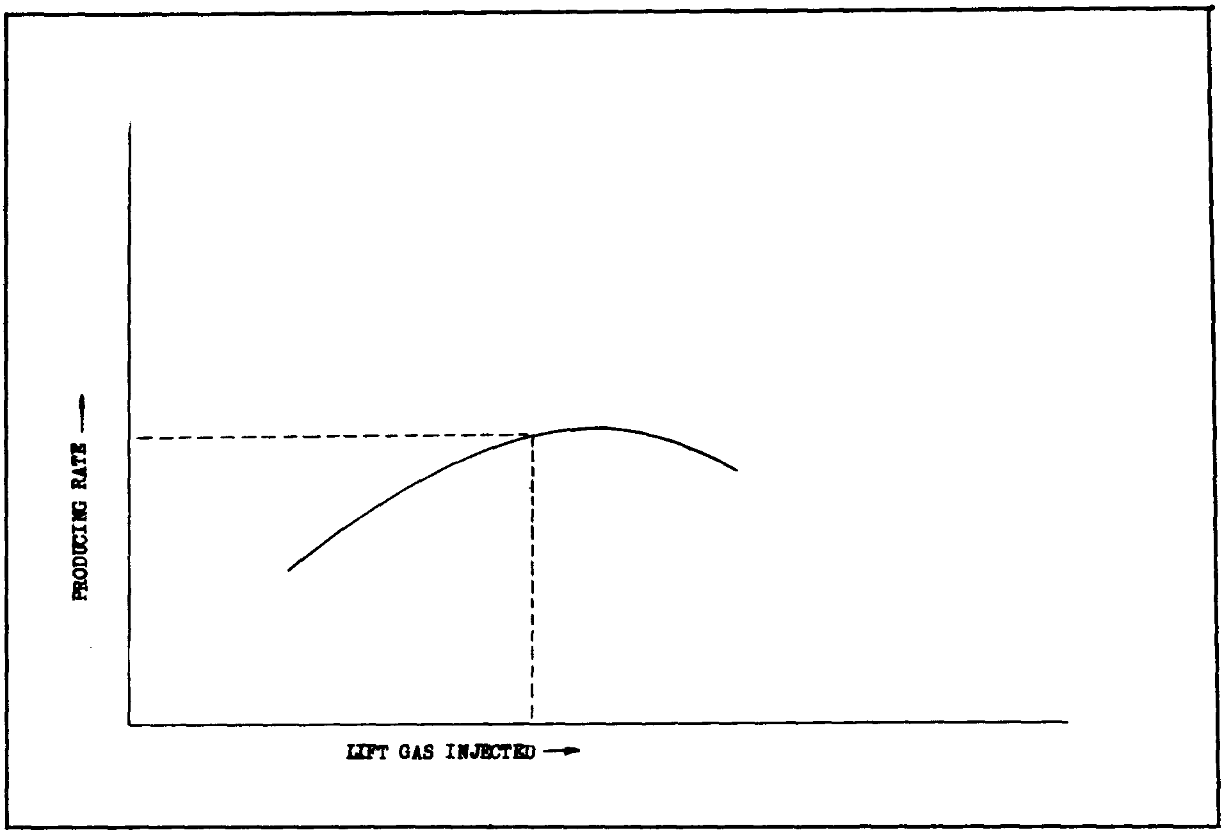

FIGURE 5

It is essential that field personnel have a working knowledge of basic production economics that are expressed as "lifting cost" or the dollars expended to produce a barrel of oil. A portion of that cost per barrel of oil produced is the cost of that volume of gas required to lift each barrel. Lift gas usage is ordinarily expressed as the thousands of cubic feet of gas required to lift a barrel of oil. This gas volume can also be expressed in dollars per barrel. For example, the cost to compress the lift gas from

These points of economics should be explained to all field personnel to help obtain the minimum required lift gas usage and therefore the minimum lifting cost.

Operating bottom-hole pressures are necessary for evaluation of the intermittent gas lift operation. A field operator must know the operating bottom-hole pressure to determine if a well is being produced at the minimum operating bottom-hole pressure thereby obtaining the maximum pressure drawdown for maximum production rates. If a well is producing from the bottom gas lift valve, the volume of lift gas used is more meaningful. By knowing the lifting depth, lift gas injected and barrels of fluid produced, the field operator can determine whether or not the intermittent gas lift installation is operating at optimum conditions. Optimum intermittent gas lift operations can only be obtained where the maximum number of operating variables are known and analyzed.

SUMMARY

A new design principle was developed to obtain maximum reservoir depletion rates, which is based on controlled valve loading and is not affected by tubing size.

Optimum intermittent gas lift operation is a function of proper design and operation. Therefore, field personnel must be knowledgeable of gas lift valve design and good field operating techniques to maintain an efficient and effective operation.

REFERENCES

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