Gas Lift Installation Design for Borderline Well

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INTRODUCTION

Gas lift is a means for producing fluid from a well after natural flow ceases or for increasing or assisting natural flow, whereby high pressure gas is used to displace or aerate the well fluid from the point of gas injection to the surface. Generally, a pressure operated gas lift valve is located at the point of gas injection and this valve controls the volume of high pressure gas which enters the conduit in which the fluid is lifted. The high pressure gas is applied for continuous flow or intermittent lift depending upon the producing characteristics of the well to be lifted. Wells with a high productivity index and high bottom hole pressure are usually gas lifted by continuous flow, and those with a low productivity index and low bottom hole pressure are intermitted. Therefore, a gas lift installation for most wells presents no problem. However, there are some wells which apparently could be gas lifted by either continuous flow or intermittent lift. A well in this category is called a borderline well and the problem is which type of gas lift installation should be run.

Borderline Well

The definition of a borderline well for this discussion is a well in which the type of gas lift installation, continuous flow or intermittent lift, is not readily apparent from the well data. Generally, the maximum producing rate possible is desired with a given injection gas pressure and volume available for lifting the well. However a knowledge of the mechanics of continuous flow and intermittent lift is needed before the proper type of gas lift installation can be selected.

Continuous Flow

Continuous flow gas lift is similar to natural flow. Continuous flow operation consists of controlled injection of high pressure gas into a flowing fluid column to cause aeration from the point of gas injection to the surface required to obtain a flowing bottom hole pressure for a desired rate of production. Injection gas supplements the formation gas from the reservoir and causes additional lightening of the flowing pressure gradient above the point of gas injection to deliver fluid to the surface.

Continuous flow operation rather than intermittent lift is generally preferred, particularly in small closed rotative gas lift systems. The high pressure injection gas enters the well and is produced to the low pressure system at a relatively constant rate. This constant production eliminates the problem of supplying large volumes of high pressure gas for short periods of time and the possibility of the venting or selling of gas from a small low pressure system due to severe heading associated with intermittent lift. The expansion of formation gas for lifting is utilized to the fullest extent in continuous flow installations and most of these installations other than a choke in the injection gas line require no control of the injection gas.

Although the advantages are numerous, there is one basic limitation to continuous flow operation. In a continuous flow installation a flowing pressure gradient above the point of gas injection always exists. Therefore, the minimum possible flowing bottom hole pressure (maximum pressure drawdown across the formation) depends on the minimum flowing pressure gradient above the point of gas injection. In many wells a higher producing rate is possible by intermittent lift than by continuous flow operation.

Intermittent Lift

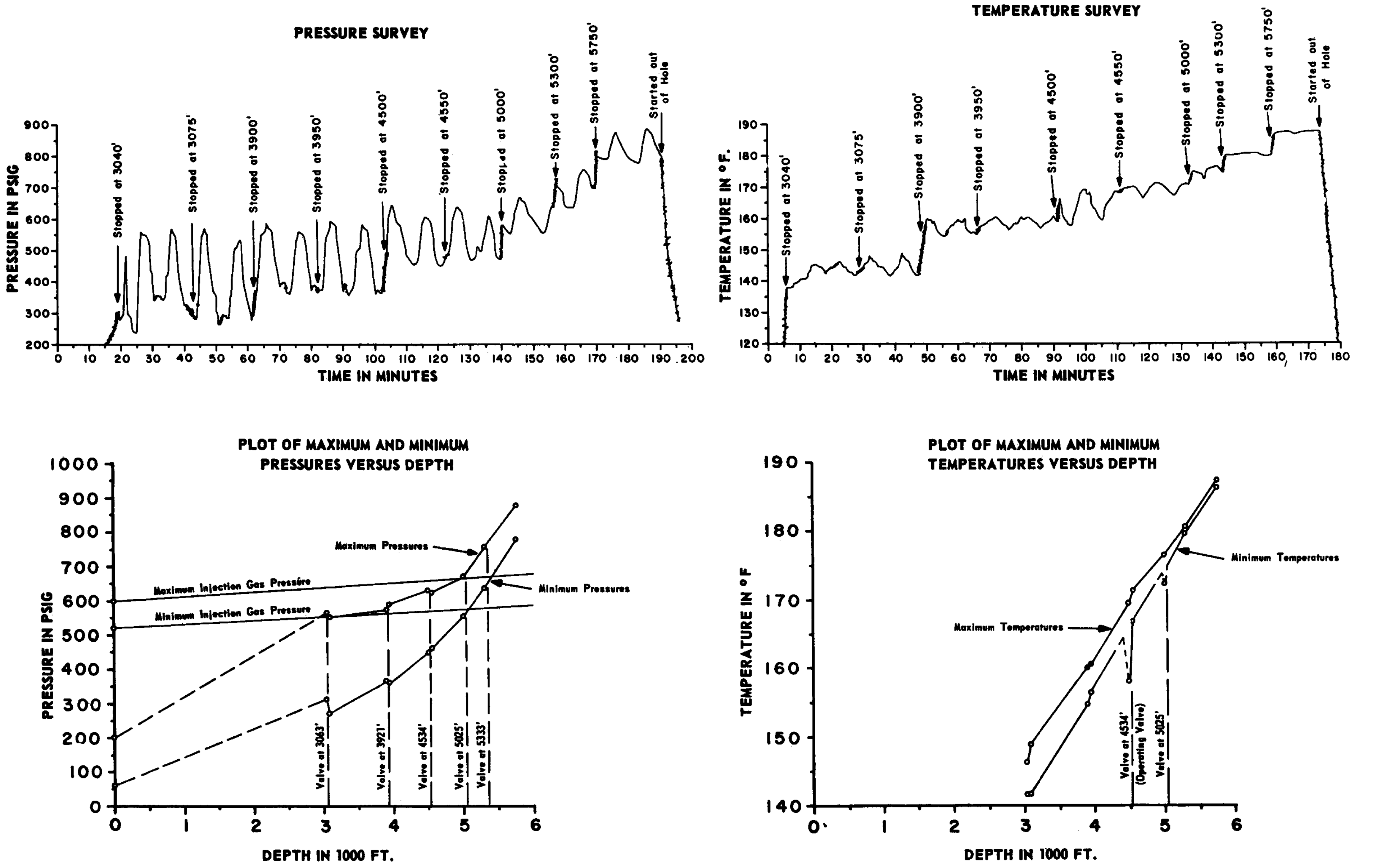
Intermittent lift operation is the displacement of a liquid slug to the surface by high pressure gas which is injected under the slug. It is primarily a displacement process, although in many installations it is a combination of displacement and aeration of the liquid slug. Most intermittent installations have a time cycle operated motor valve (commonly referred to as a surface controller) on the injection gas line. When the controller opens, the casing pressure increases to the opening pressure of the operating gas lift valve in the well. Then when the gas lift valve opens, injection gas enters the tubing through the valve and displaces the liquid slug above the valve to the surface. The controller closes, and after the casing pressure decreases to the closing pressure of the valve the operating gas lift valve closes.

The injection gas cycle frequency (number of gas injections per day) can be varied by changing injection intervals on the timing wheel in the time cycle pilot of the controller. A properly designed intermittent lift installation, particularly a chamber installation, will result in the minimum flowing bottom hole pressure possible by gas lift methods in a low capacity well due to the low pressure gradient above the liquid level in the tubing. If there is sufficient time between gas injections, no flowing pressure gradient remains between the fluid level in the tubing and the surface; only a static gas gradient exists based on the surface wellhead pressure. The primary disadvantage of an intermittent installation in a well with a reasonably high capacity relative to tubing size, depth of lift, etc., is that the maximum producing rate is limited. The producing rate is a function of the injection gas cycle frequency which decreases with depth, excessive back pressure, etc.

FACTORS AFFECTING DESIGN OF GAS LIFT INSTALLATIONS

The following factors should be evaluated to select the proper type of gas lift installation:

1. Desired producing rate
2. Approximate flowing bottom hole pressure for desired producing rate
3. Depth to the point of gas injection
4. Injection gas pressure available at the well
5. Injection gas volume available at the well
6. Flowing wellhead tubing pressure.



PRESSURE SURVEY
PRESSURE IN PSIG
TIME IN MINUTES
Stopped at 3040'
Stopped at 3075'
Stopped at 3900'
Stopped at 3950'
Stopped at 4500'
Stopped at 4550'
Stopped at 5000'
Stopped at 5300'
Stopped at 5750'
Started out of Hole
TEMPERATURE SURVEY
TEMPERATURE IN °F.
TIME IN MINUTES
PLOT OF MAXIMUM AND MINIMUM PRESSURES VERSUS DEPTH
PRESSURE IN PSIG
DEPTH IN 1000 FT.
Maximum Pressures
Minimum Pressures
Maximum Injection Gas Pressure
Minimum Injection Gas Pressure
Valve at 3063'
Valve at 3921'
Valve at 4534'
Valve at 5025'
Valve at 5333'
PLOT OF MAXIMUM AND MINIMUM TEMPERATURES VERSUS DEPTH
TEMPERATURE IN °F
DEPTH IN 1000 FT.
Maximum Temperatures
Minimum Temperatures
Valve at 4534' (Operating Valve)
Valve at 5025'

FIGURE 1

Other factors which affect gas lift operation and maximum daily producing rate are the tubing size, formation gas-liquid ratio, etc. In extremely high gas-liquid ratio wells, there have been reported very low flowing pressure gradients, such as 0.08 psi/ft in 2-7/8 in. O.D. tubing. Therefore, wells with high gas-liquid ratios can be lifted by continuous flow with the points of gas injection very deep and nominal injection gas pressure.

The primary factors affecting the design of a gas lift installation are the producing rate, the flowing bottom hole pressure required to induce this producing rate, and the point of gas injection necessary to obtain this flowing bottom hole pressure. Although all these factors may be known for a well, the type of installation–namely continuous flow or intermittent lift – may not be obvious. When this situation arises, both types of gas lift design should be calculated and the maximum producing rates and gas requirements should be estimated for each type of installation. But if the results of these calculations are not conclusive, one installation should be designed which would allow both continuous flow and intermittent lift. In order to successfully intermit an installation, small chokes cannot be used in the gas lift valves. Although it is not widely applied, most pressure operated gas lift valves without chokes can be used for either continuous flow or intermittent lift.

GAS LIFT INSTALLATION IN BORDERLINE WELL

A gas lift installation was designed and run in a borderline well, and it was assumed that no difficulty would be encountered obtaining the desired producing rate. The installation was designed by using the following general well data:

1. Tubing size - 2-3/8 in. O.D. (2 in. EUE nominal)
2. Casing size - 5-1/2 in. O.D.
3. Total depth - 5750 ft
4. Desired producing rate - 300 BLPD
5. Water cut - 85 per cent
6. Static fluid gradient - 0.45 psi/ft
7. Static bottom hole pressure - 1730 psig at 5750 ft
8. Separator pressure - 60 psig
9. Kick-off injection gas pressure at well - 700 psig
10. Operating injection gas pressure at well - 600 psig
11. Injection gas volume - 650 MCFD

The installation was designed for intermittent lift; therefore, the gas lift valves were not choked. After the installation was installed, the maximum daily producing rate from the well was 272 barrels per day by intermittent lift with a high injection gas cycle frequency (192 gas injections per day). By continuous flow the producing rate was less than one-half the maximum rate possible by intermittent lift. In an effort to increase the daily producing rate, it was decided to analyze the present operation and determine whether a change in the gas lift design would increase the daily producing rate.

Analysis of Gas Lift Installation

While the well was producing at a maximum producing rate by intermittent lift, temperature and pressure surveys were conducted to determine the operating gas lift valve and the flowing bottom hole pressure. A static bottom hole pressure had been previously obtained in this well, and the bottom hole pressure in the field was not changing.

The results of the flowing pressure and temperature surveys are plotted in Fig. 1.[1] The point of gas injection was "pin-pointed" by a temperature survey and found to be at the depth of the third valve, 4534 ft. Some gas was entering the tubing through the next lower valve at 5025 ft. From the flowing pressure survey the following information was obtained while the well was producing 272 barrels of liquid per day:

1. Average flowing bottom hole pressure - 825 psig at 5750 ft
2. Average flowing pressure gradient for traverse below point of gas injection - 0.33 psi/ft
3. Productivity Index = $\dfrac{272 \text{ bbls/day}}{1730 \text{ psig} - 825 \text{ psig}}$

0.3 BPD/psi

Design of Continuous Flow Installation For Maximum Producing Rate

The maximum producing rate from a well with a continuous flow installation can be determined with flowing pressure gradient curves if the bases for the curves are similar to actual well data. But this determination requires a trail-and-error solution. The point of gas injection for the maximum producing rate from a continuous flow installation is based on the operating injection gas pressure, the pressure differential across the valve, and the traverse above the point of gas injection. The maximum pressure drawdown across a formation is obtained by attaining the minimum possible flowing pressure gradient above the point of gas injection with the available injection gas volume and lifting from the greatest depth possible based on the operating injection gas pressure. If the injection gas volume is ample, the minimum fluid gradient curve is used to estimate the maximum producing rate. Otherwise the gas-liquid ratio must be based on the injection gas volume available to lift the well. The minimum fluid gradient curve represents the lowest flowing pressure gradient attainable regardless of the injection gas volume. Therefore, it represents the minimum possible flowing tubing pressure at the point of gas injection, the maximum pressure producing rate possible.

In this installation the point of gas injection by continuous flow could be determined based on the flowing pressure traverse above the point of gas injection, the operating injection gas pressure at depth curve, and the assumed pressure differential across the valve. Since the flowing wellhead tubing pressure ranged between 60 and 200 psig while intermittently lifting the well at maximum producing rate, a flowing wellhead tubing pressure of 100 psig was assumed for continuous flow operation. There were approximately 650 MCFD of injection gas volume available to lift the well. This volume of injection gas was ample to attain the minimum fluid gradient curve to the predicted depth of the operating valve. As can be noted from the set of flowing pressure gradient curves in Fig. 2, the gas-liquid ratio required to establish the minimum fluid gradient curve increases with depth.[2] To simplify the procedure for estimating the maximum producing rate, the graph tracing paper (workpaper) and the flowing pressure gradient curves should have the same pressure and depth scales which allow tracing the flowing pressure traverses by overlaying the workpaper on the proper set of gradient curves. The graphical solution to this problem is illustrated in Fig. 3. The prooximate maximum producing rate from this well is determined by the following steps:

Step 1

The injection gas pressure at depth curve based on

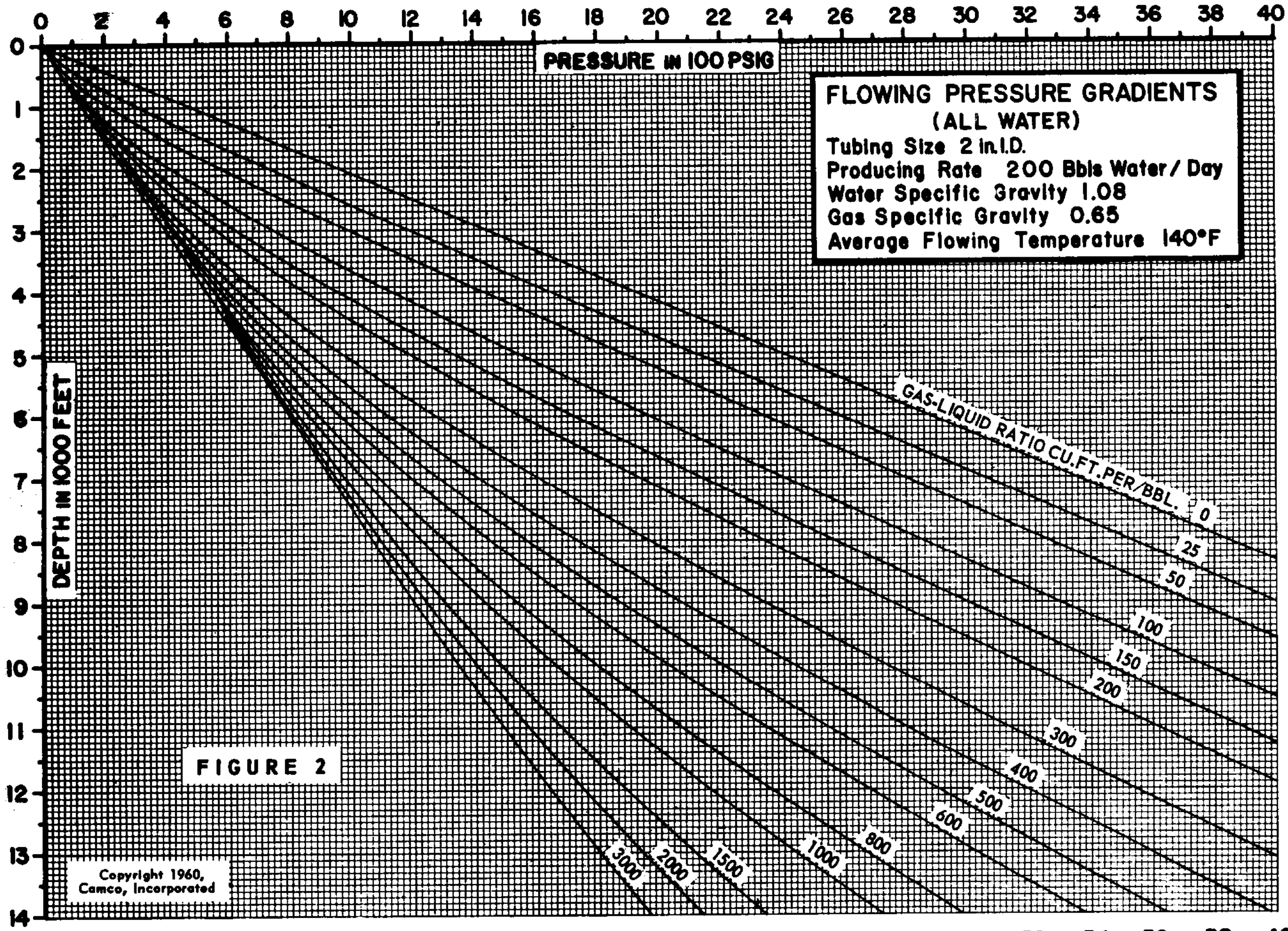


FIGURE 2

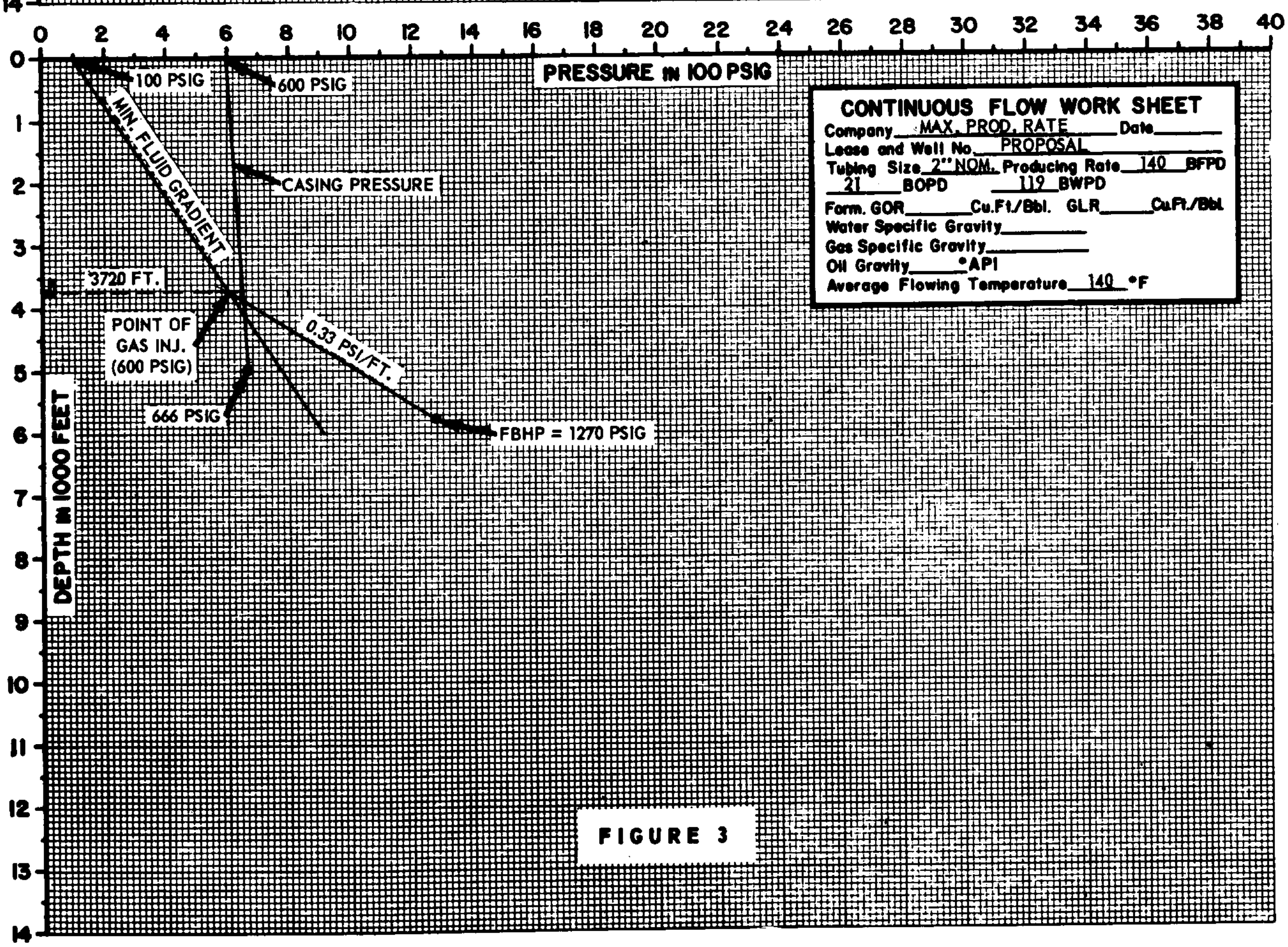


FIGURE 3

the operating injection gas pressure of 600 psig is drawn. For this installation the increase in gas pressure with depth is equal to approximately 2.2 psi per 100 psig surface pressure per 1000 ft of depth.

600 psig at surface increase to 666 psig at 5000 ft

Step 2

The minimum fluid gradient curve for the assumed producing rate and a flowing tubing pressure of 100 psig at zero depth is drawn. The first assumption presumes that the well will produce approximately 200 BLPD. Flowing pressure gradient curves for 200 BWPD at an average temperature of 140 F through 2 in. nominal tubing are given in Fig. 2. The graph tracing paper is shifted downward with the ordinate of the graph tracing paper overlaying the ordinate of the gradient curves until the minimum fluid gradient curve passes through 100 psig on the abscissa of the workpaper; then the minimum fluid gradient curve is traced.

Step 3

The point of gas injection and approximate flowing tubing pressure at this depth based on a 50 psi pressure differential across the operating valve is determined. A 50 psi pressure difference between the casing and tubing pressures at valve depth is recommended to assure ample gas passage through the valve with minor fluctuations in injection gas line pressures.

Approx. Depth of Operating Valve - 3720 ft
Flowing Tubing Pressure at Depth of Operating Valve - 600 psig at 3720 ft

Step 4

The approximate flowing bottom hole pressure at 5750 ft is calculated if the flowing presure gradient below the point of gas injection is 0.33 psi/ft.

FBHP = Pt at 3720 ft + 0.33 psi/ft (5750 ft - 3720 ft)

= 600 psig + 670 psig = 1270 psig at 5750 ft

Note: If the flowing pressure gradient below the point of gas injection is unknown, the flowing bottom hole pressure can be determined by using gradient curves.

Step 5

The approximate producing rate for a flowing bottom holw pressure of 1270 psig at 5750 ft and a productivity index of 0.3 BPD/psi is calculated and this calculated producing rate is compared with the assumed producing rate.

Approx. Producing Rate = P. I. (Drawdown)
= 0.3 BPD/psi(1730 psig-1270 psig)
= 138 BPD

There is no reason to recalculate a continuous flow design for this installation by assuming a lower producing rate and using the proper set of gradient curves for the lower producing rate since a previous production test of this well indicated a producing rate of 272 BPD by intermittent operation with a high injection gas cycle frequency. In other words, to obtain capacity production continuous flow design is not recommended for this well. Approximately 140 BLPD is apparently the maximum producing rate possible by continuous flow operation.

Design of Intermittent Lift Installation For Maximum Producing Rate

Since a continuous flow design has been ruled out, redesign of the intermittent installation should be investigated. From an analysis of the intermittent installation in the well, the approximate depth for the proposed operating gas lift valve can be established.

In an intermittent installation the pressure gradient above the point of gas injection for locating the valve depth is generally considered a spacing factor rather than a true flowing gradient. However, in an intermittent lift installation with a high injection gas cycle frequency, a flowing gradient does exist between gas injections because the liquid phase does not have sufficient time to accumulate as a liquid slug above the operating gas lift valve before this valve reopens. In this particular well the minimum flowing pressure gradient (spacing factor) in psi per foot above each valve between gas injections can be calculated from the flowing pressure survey. Since this information is available, it should be used in the proposed redesign of the installation. The actual average minimum flowing pressure gradients which existed above ach valve during the flowing pressure survey were 0.062 psi/ft above the valve at 3063 ft, 0.077 psi/ft above the valve at 3921 ft, and 0.088 psi/ft above the valve at 4534 ft. These are approximate flowing pressure gradients based on a minimum flowing tubing pressure of 60 psig between gas injections. The gradient increased above each succeedingly lower gas lift valve (increased depth of lift). Therefore, it is a good practice to design a high capacity intermittent installation using increasing spacing factors (flowing pressure gradients) with increased depth.

A recommended procedure for calculating the depth of the gas lift valves in an intermittent installation is to base each valve depth on the closing pressure of the valve above at its depth. The injection gas column weight, valve operating temperature, gas lift valve specifications, etc., are all considered in this design technique. A decreasing surface closing pressure for each succeedingly lower valve is assumed, and this casing pressure at valve depth is used to calculate the depth of the next lower valve. Then, after the valve depths are calculated, the valve opening pressures at 60 F in a tester are calculated, and the calculations will result in the assumed surface closing pressures. This design procedure has been outlined in a previous article.

In the proposed intermittent installation, the top valve is located near the static fluid level and the remaining valve depths were calculated based on assumed surface closing pressures. Spacing factors beginning with 0.04 psi/ft and increasing to 0.088 psi/ft were used to calculate the depths of the top five valves. The depth of the sixth valve was arbitrarily selected to be 5,000 ft. There should be no difficulty unloading the well with the proposed installation because of two safety factors included in the calculations, namely, the static fluid gradient and a flowing wellhead tubing pressure of 100 psig used to calculate the valve depths.

The second, third and fourth valves in the proposed installation are at approximately the same depths as are the first, second and third valves in the actual installation. However, the distance between the third and fourth valves in the actual installation is too great; therefore, the distances between the bottom valves were significantly reduced in the proposed installation. But the well can be lifted from the bottom valve in the proposed installation because the casing pressure will be higher while lifting from this valve because of the higher opening pressures of the unloading valves. In the actual installation the top valve is located at a depth equal to the calculated depressed fluid level which is attained by simultaneously applying, for a period of time required to lower the fluid level in the well, the injection gas line pressure to the casing and the tubing. However this method for locating the top valve in a gas lift installation is not recommended and cannot be used if a packer and standing valve are run into the well.

In an intermittent intallation it is desirable for the surface closing pressure of the operating gas lift valve to be at least 100 psi less than the injection gas line pressure so that the casing pressure will increase rapidly after the surface controller opens.[4, 5] Since the depth of the operating valve in the proposed installation can be determined from the pressure survey prior to running the installation, the upper valve opening pressures can be selected to take advantage of the maximum kick-off line pressure. The operating valve for the proposed installation should be the valve at 5,000 feet; this location will result in 125 psi difference between the line pressure and the surface closing pressure of this valve. But if the well should be lifted from the valve at 4800 feet, there would be a 100 psi difference which would still result in satisfactory operation. However, the approximate point of gas injection was not known when the actual installation was designed. Consequently, it was necessary to significantly decrease the opening pressures of the upper valves so that the well could be lifted from any valve below the second valve and so that the third valve was the operating valve.

The kick-off injection gas pressure can be utilized only for locating the unloading valves in any gas lift installation. The opening pressures of all gas lift valves which possibly could be the operating valve must be based on the operating injection gas pressure. When the kick-off pressure is greater than the operating pressure and the approximate depth of the operating valve is known, the depths of the upper unloading valves can be based on the kick-off injection gas pressure.

CONCLUSIONS

A redesigned intermittent installation for the well discussed in this paper was not run. After correlating the results of the subsurface surveys with the production tests and studying the proposed intallation, it was concluded that respacing the valves would not result in an appreciable increase in production. In the opinion of the operator, the additional bottom hole pressure drawdown and probable small increase in production by lifting from a lower valve at 5,000 ft could not justify the cost of respacing the valves.

As can be seen from this problem, the type of design for a gas lift installation is not always readily apparent from well data. Generally, continuous flow installation would be considered the most suitable type of gas lift design to produce 300 BLPD through 2 in. tubing. However, for the well data used in this paper, the desired producing rate of 300 BLPD could not be gas lifted with a continuous flow installation. The installation just be designed for intermittent lift using a high injection gas cycle frequency for capacity production.

If flowing pressure gradient curves with bases similar to well conditions are available the maximum producing rate prossible by continuous flow can be predicted with considerable accuracy. However this prediction is not obtainable for intermittent lift operation. Since it is not difficult to predict the producing rate by continuous flow, the producing rate by this type of gas lift operation should be determined first when the desired rate of production is several hundred barrels per day. If it is obvious that the desired producing rate cannot be gas lifted by continuous flow operation because of limited bottom hole pressure drawdown, the installation should be designed for intermittent lift.

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ACTUAL INSTALLATION

Valve No.	Depth of Valve (ft.)	Opening Pressure at 60° F in Tester (psig)
1	3063	650
2	3921	600
3	4534	550
4	5025	500
5.	5333	450

PROPOSED INSTALLATION

Valve No.	Port Size (in.)	Depth of Valve (ft.)	Surface Closing Pressure of Valve (psig)	Opening Pressure at 60° F in Tester (psig)
1	5/16	2000	650	670
2	5/16	3100	625	645
3	5/16	3950	600	615
4	5/16	4500	575	590
5	3/8	4800	500	550
6	3/8	5000	475	525