The Application of Pressure and Temperature Surveys to Gas Lift Installations

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INTRODUCTION

The purpose of this paper is to illustrate the application of pressure and temperature surveys to gas lift installations, not to discuss the mechanics of bottom hole pressure and temperature instruments. The advantages of pressure surveys prior to the installation of gas lift equipment are discussed. The procedure for running surveys in intermitting gas lift wells is offered. The determination of the operating valve or valves, using both the temperature and pressure survey in the same well, is presented. Examples of surveys in a gas lift well with a tubing leak and a well with leaky valves are given. Bottom hole pressure surveys for chamber installations are noted which show the minimum flowing bottom hole pressures obtained with low pressure versus high pressure operating gas lift valves. The paper concludes by illustrating the use of a pressure survey for estimating per cent fallback in an intermitting gas lift installation.

PRESSURE SURVEY PRIOR TO GAS LIFT INSTALLATION

Importance of Static Fluid Level

A reliable static fluid level can be obtained from a pressure survey. Spacing the top gas lift valve at the static fluid level can save an operator several thousand dollars in a low bottom hole pressure, deep well. The savings will be shown by an actual example.

An operator ordered wire line retrievable gas lift equipment for a 13,000 foot well in West Texas. The operator specified that the top valve be spaced at a depth of approximately 1,500 feet, based on the injection gas pressure. The well was believed to have a high bottom hole pressure and fair productivity index. After the gas lift valves were installed, the well was unloaded and operated unsatisfactorily. Various injection gas frequencies were tried without success. Finally, a bottom hole pressure survey was conducted. The point of gas injection was found to be at a depth of nearly 10,000 feet, which had been suspected because of the low operating injection gas pressure. The static fluid level was below 6,000 feet. Five mandrels, retrievable valves, and latches had been run above the fluid level. This equipment alone represented nearly $3,000. The top five gas lift valves were pulled with wire line tools and replaced with dummy blanking valves. The lower gas lift valves were also pulled and replaced with higher pressure valves to gas lift the well efficiently from 10,000 feet with the available injection gas pressure.

If the operator had run a pressure survey prior to installing gas lift valves, he would have saved the initial equipment cost of at least six gas lift valves, latches, and mandrels; eliminated the wire line expense of changing the gas lift valves; and prevented loss of production. The lower mandrels could have been spaced further apart by assuming the kickoff injection gas pressure for the top valve at 6,000 feet, thus saving one or more valves below the static fluid level. Fortunately, the gas lift valves were wire line retrievable and the design could be changed at a relatively low cost.

Productivity Index for Proper Design

The static and flowing bottom hole pressures should be obtained prior to designing the gas lift installation. With this information a productivity index can be determined and the proper gas lift valve design calculated. The maximum temperature obtained during the pressure survey should be used to establish a temperature gradient for calculating gas lift valve operating pressures at valve depths in the well.

Flowing Pressure Traverse for Continuous Flow

A flowing pressure traverse below the point of injection is needed to calculate the depth of the operating valve in a continuous flow installation. A pressure traverse is established by recording flowing pressures at several depths between the required point of gas injection and total depth. If the well is on gas lift and it is desired to improve the installation, the flowing gradient below the point of gas injection can be established before pulling the valves.

The operator can readily calculate the point of gas injection for the available injection gas pressure and desired flowing bottom hole pressure when an average flowing gradient below the point of gas injection is known, as shown in Fig. 1. This procedure for locating the operating valve is widely used in the Texas-Louisiana Gulf Coast area where the reservoir pressure does not change appreciably with time. The point of gas injection determined by this method with accurate pressure data results in minimum gas requirements.

Pressure Build-up Curve for Intermittent Design

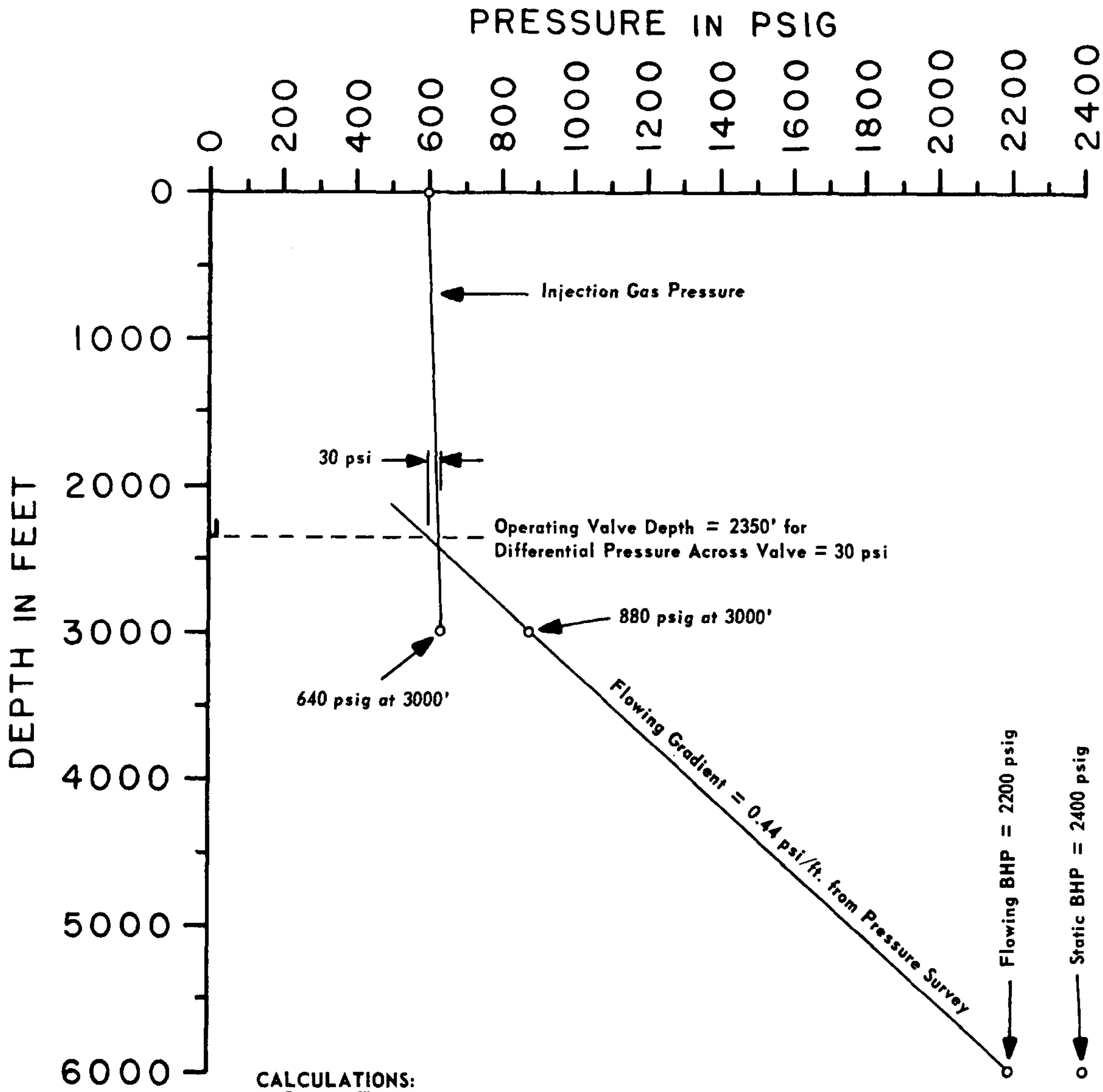
A pressure build-up curve is useful for properly designing an intermittent gas lift installation and determining the proper injection gas frequency for maximum production. A pressure build-up curve is an indication of a reservoir's capability to deliver fluid into the well-bore. Hypothetical pressure build-up curves for two types of intermitting wells are shown in Fig. 2. Generally, the pressure will increase rapidly at the beginning of the test when the difference between the static and flowing bottom hole pressure is great, as indicated by Curve 1. In time, the increase in pressure diminishes as the differential is reduced.

Curve 1, which is typical of many intermitting gas lift wells, illustrates a well with a higher bottom hole pressure and much lower productivity index than the well illustrated by Curve 2. The depth of the operating valve, injection gas cycle frequency, and tubing size selection can be determined from the pressure build-up curve. For maximum production, the average flowing bottom hole pressure should be maintained in the steeper portion of Curve 1. A smaller tubing size, such as 2 inch nominal, is generally preferred for this type

DETERMINING DEPTH OF OPERATING VALVE FOR
CONTINUOUS FLOW GAS LIFT WELL

GIVEN: Producing 800 BFPD (WOR 19:1)
Static BHP = 2400 psig at 6000'
Productivity Index = 4.0
Flowing Gradient Below Point of Gas Injection = 0.44 psi/ft.
Operating Injection Gas Pressure = 600 psig at Well

FIND: Depth of Operating Valve



CALCULATIONS:

$$\text{Drawdown} = \frac{\text{BFPD}}{\text{P.I.}} = \frac{800}{4} = 200 \text{ psi}$$

Flowing BHP = Static BHP − Drawdown = 2400 − 200 = 2200 psig

Establish Flowing Gradient Curve:

Pressure at 3000' = 2200 psig − (6000' − 3000') 0.44 psi/ft.
= 2200 − 1320 = 880 psig at 3000'

Establish Injection Gas Pressure Curve from Appropriate Gas Weight Curves:

600 psig at Surface = 640 psig at 3000'

FIG. 1

of well to provide more efficient intermitting lift for maximum drawdown.

The third curve is a plot of time versus rate of feed-in for the high bottom hole pressure, low productivity well (Curve 1). It illustrates the need of remaining in the steeper portion of the build-up curve for maximum production in many intermitting wells with a similar

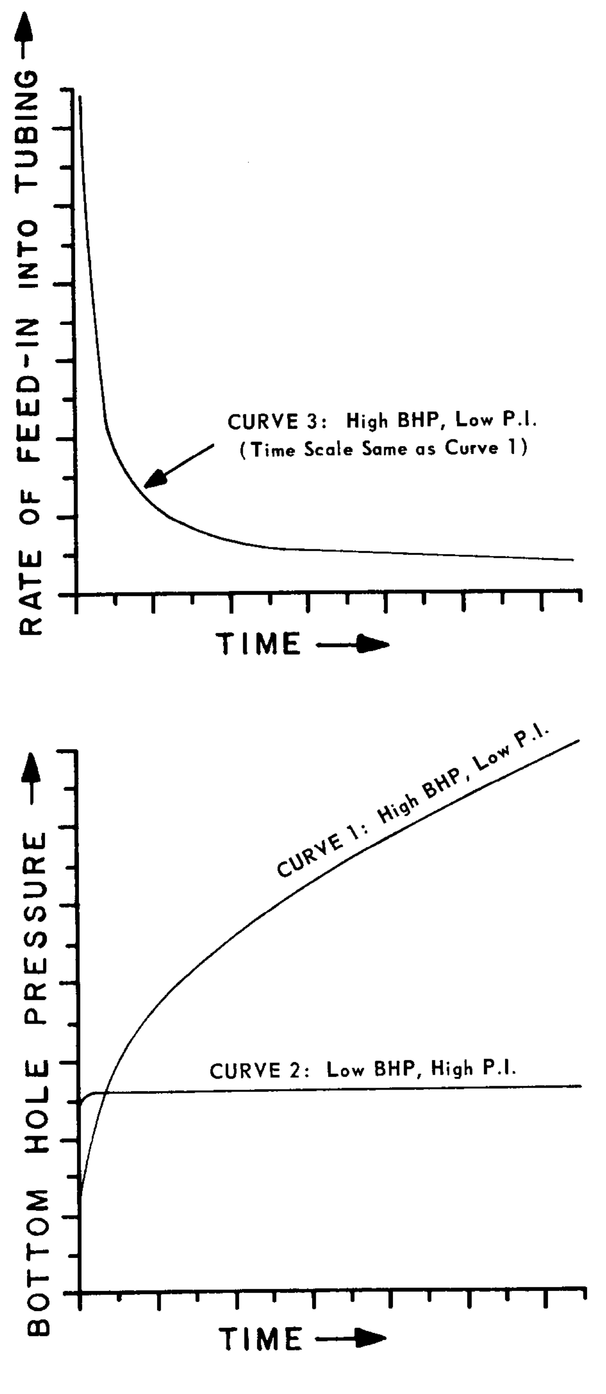


FIG. 2 Two Hypothetical Pressure Build-up Curves for Two Types of Intermitting Wells and One Rate of Feed-in Curve.

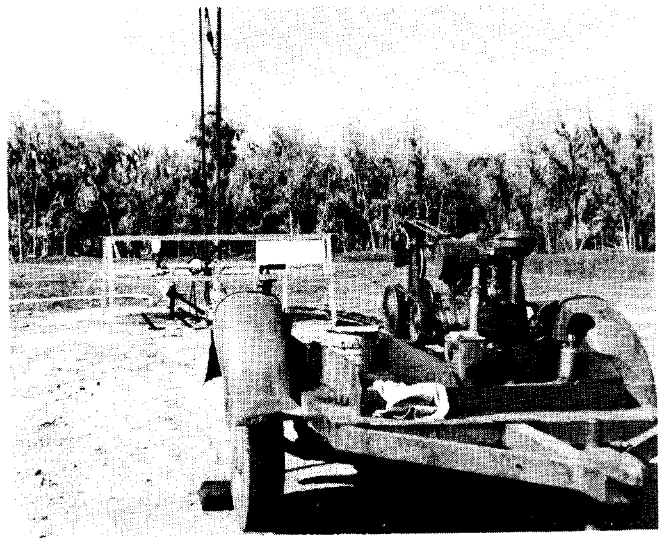


FIG. 3: Wire Line Trailer and Lubricator used to run bomb and special weighted stem in an intermittent gas lift well.

pressure build-up curve. However, there are wells which should not be produced with an excessive drawdown. Depending upon the type of oil reservoir, excessive drawdown can result in wells producing practically all gas or being ruined by coning water.

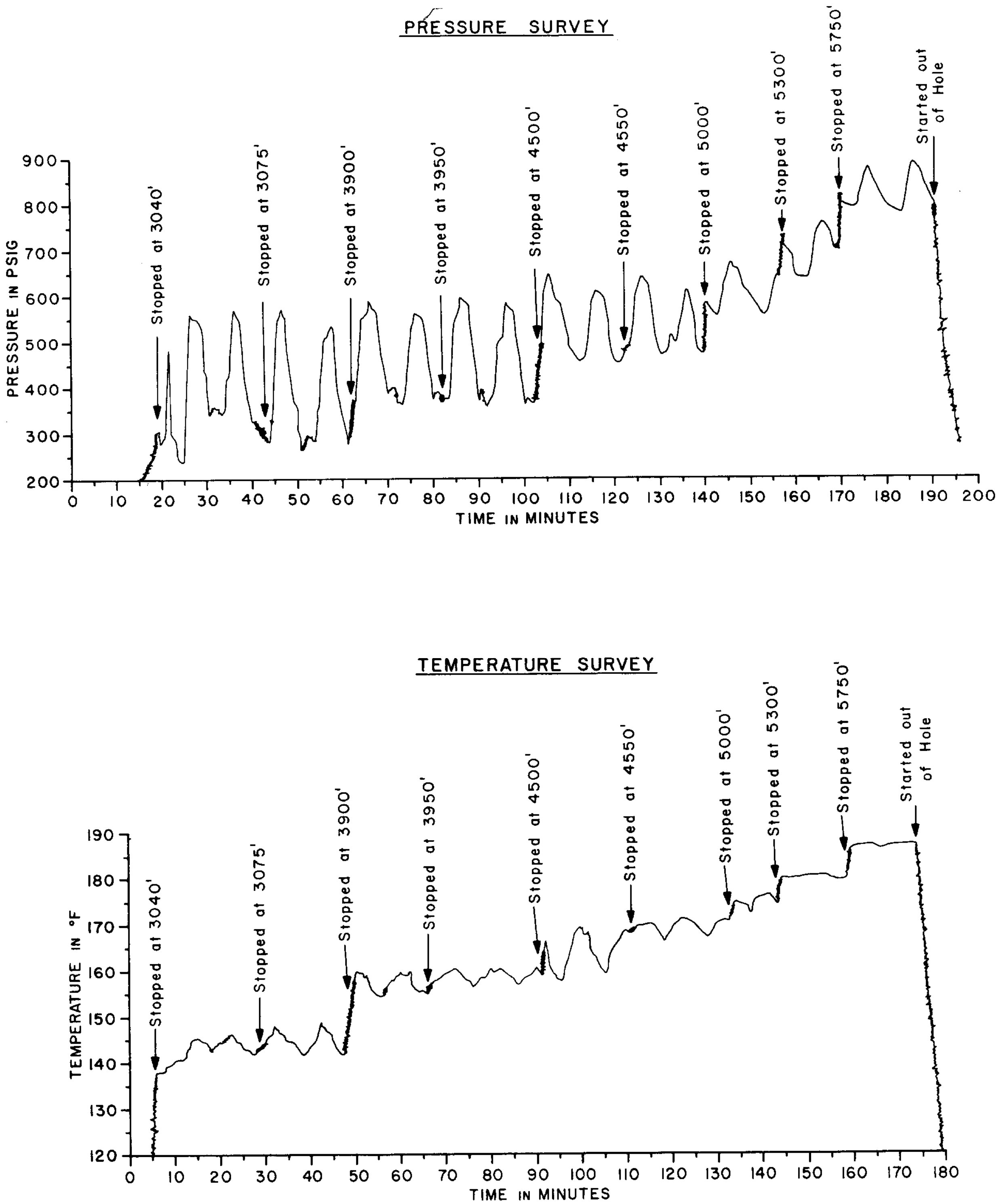
Curve 2 illustrates a well with a low bottom hole pressure and high productivity index. A chamber design should be used for gas lifting this type of well. For maximum producing rate, a large tubing size should be employed. The chamber installation is superior to a plunger installation because the maximum number of injection gas cycles per day significantly exceeds those possible with a plunger. In the plunger installation, production is lost due to the time required for the plunger to return to the bottom of the well.

CONDUCTING SURVEYS IN INTERMITTING WELLS

Certain precautions are necessary for conducting a pressure or temperature survey in a producing intermitting gas lift well. In some wells the survey must be conducted while producing the well to determine the operating valve or efficiency based on liquid fall-back. The depths of all gas lift valves should be known prior to beginning the survey. Most difficulty in running the bomb will generally occur above the fluid level when the liquid slug being lifted by the injection gas slams into the bomb.

If a temperature survey is being conducted to determine the operating valve, it is desirable to record the temperature in the tubing immediately above and below each gas lift valve below the fluid level. There is no reason to begin the survey until the fluid level is reached, since the operating valve must be below this depth. This would be true for the pressure survey also. Recording depths for the pressure survey are not as critical as those for the temperature survey. The bomb with a temperature element should not be stationed too far above each valve to positively detect any cooling effect from injection gas entering the tubing through an open valve. The temperature or pressure bomb should remain at each recording depth throughout at least one, preferably two, complete injection gas cycles.

There have been special tools designed to prevent a bomb from being blown up the hole. These devices have one disadvantage. If the tool will prevent a bomb from being blown up the tubing, the tool is capable of sticking



PRESSURE AND TEMPERATURE SURVEYS IN THE SAME INTERMITTING GAS LIFT WELL TO LOCATE OPERATING VALVE

FIG. 4

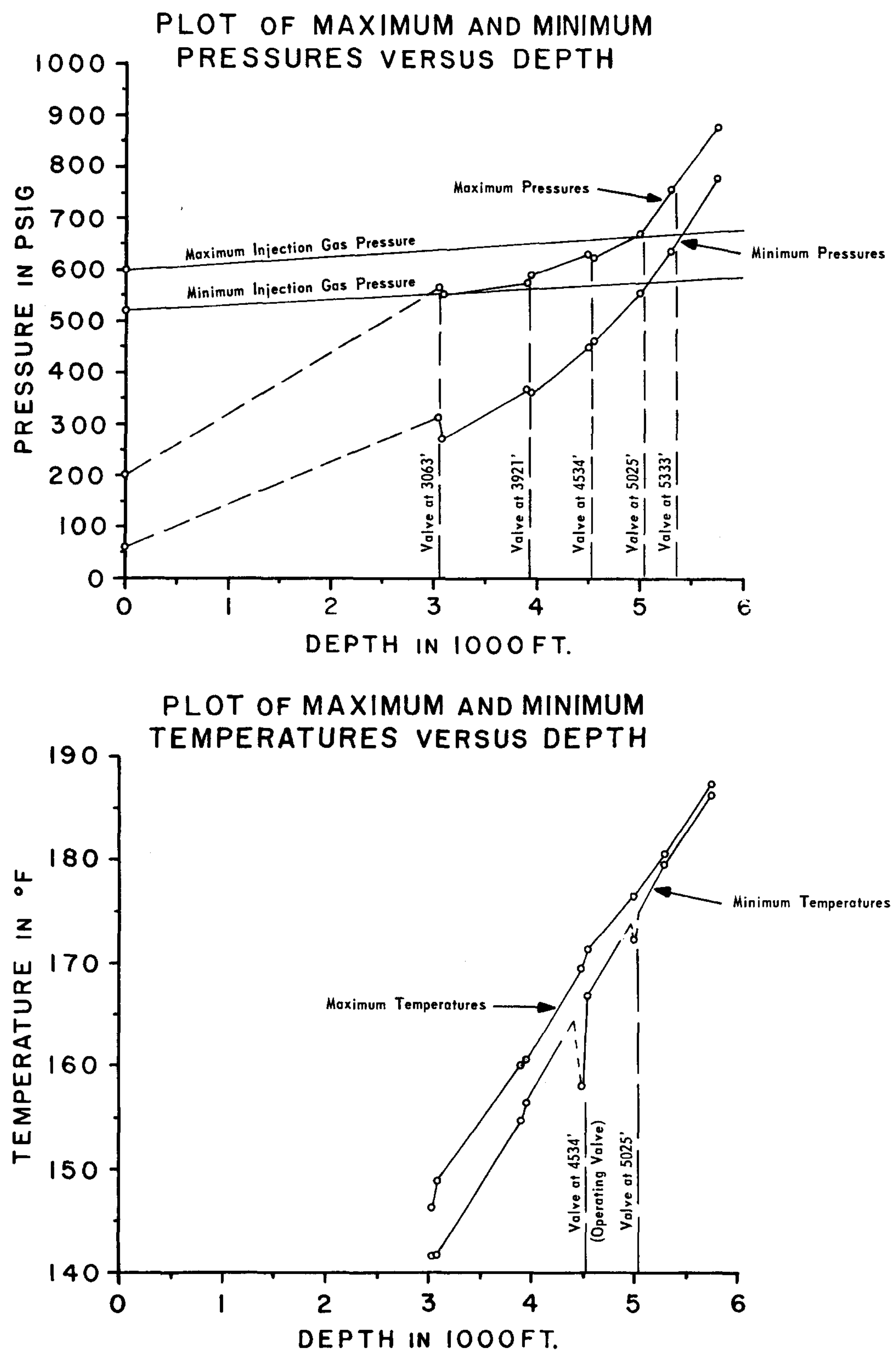


FIG. 5

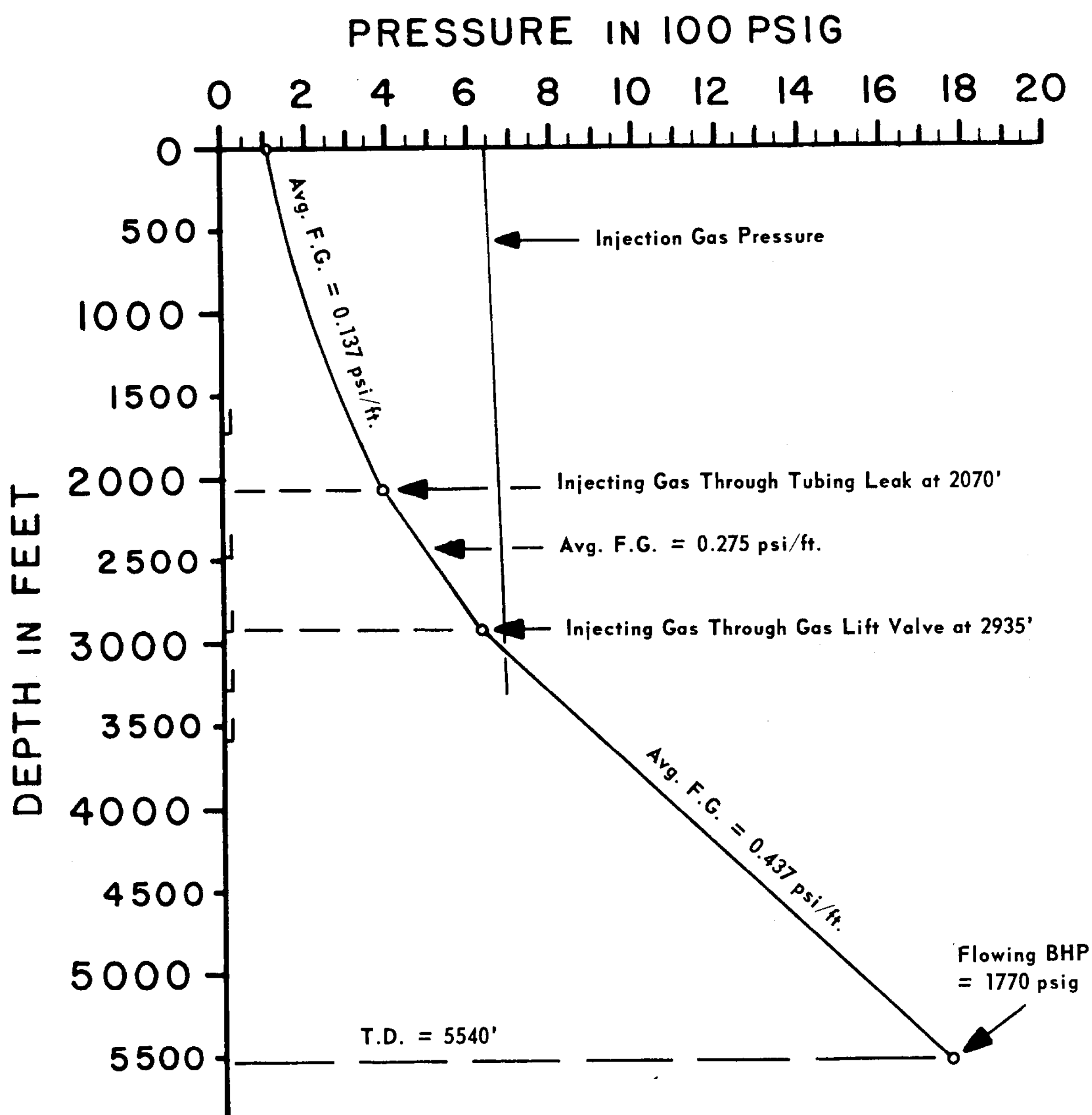
RESULTS OF PRESSURE AND TEMPERATURE SURVEYS IN FIGURE 4 FOR LOCATING OPERATING GAS LIFT VALVE IN AN INTERMITTING WELL

FIG. 6

LOCATING A TUBING LEAK FROM A PRESSURE SURVEY IN A CONTINUOUS FLOW GAS LIFT WELL

WELL DATA:

2" Tubing in 5-1/2" O.D. Casing
Producing 640 BFPD (5 BOPD)
Injection Gas-Liquid Ratio = 550:1
Surface Injection Casing Pressure = 640 psig
Producing Wellhead Tubing Pressure = 110 psig



NOTE: All average flowing gradients (F.G.) were determined from a pressure survey.

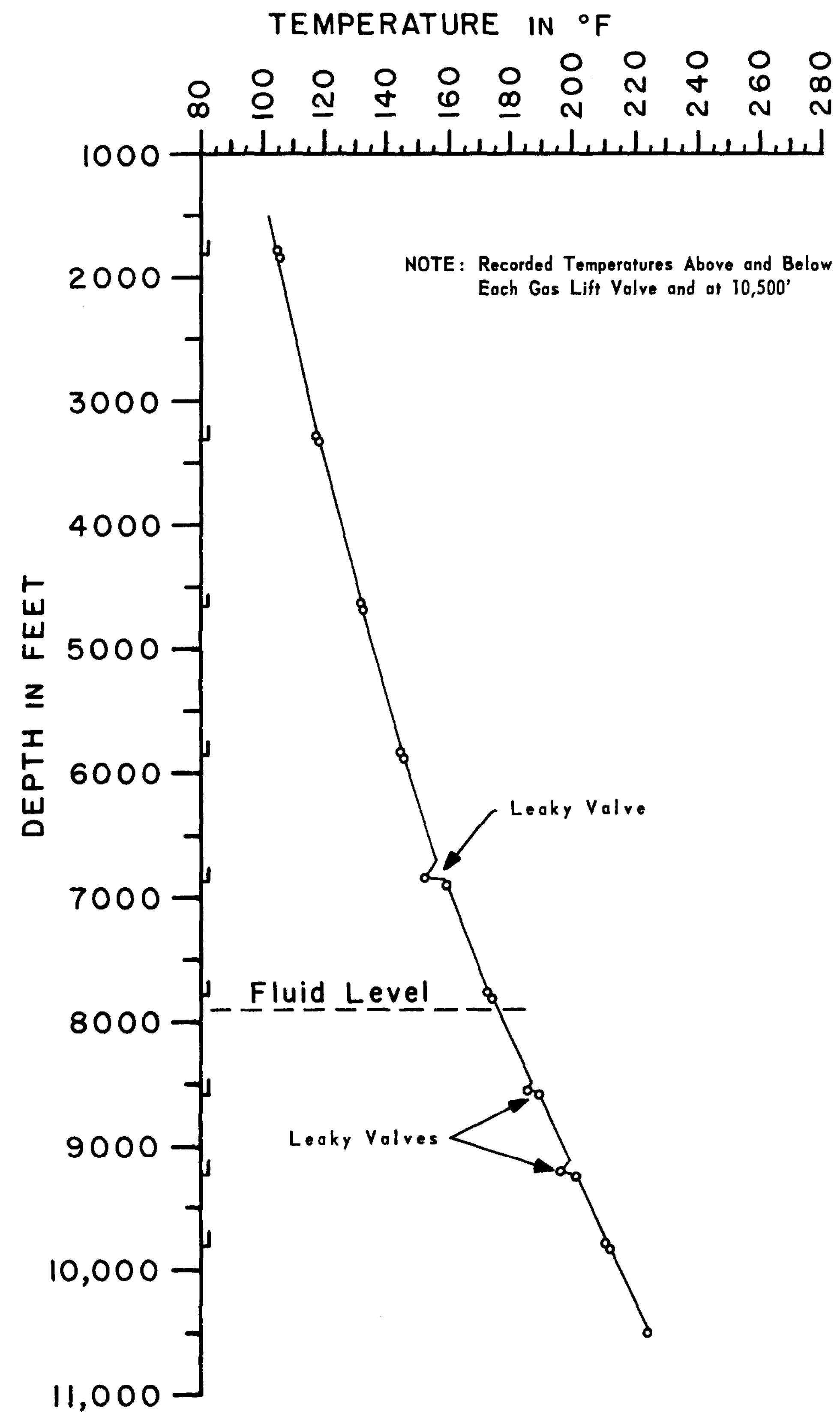


FIG. 7 RESULTS OF TEMPERATURE SURVEY IN INTERMITTING GAS LIFT WELL FOR LOCATING LEAKY VALVES.

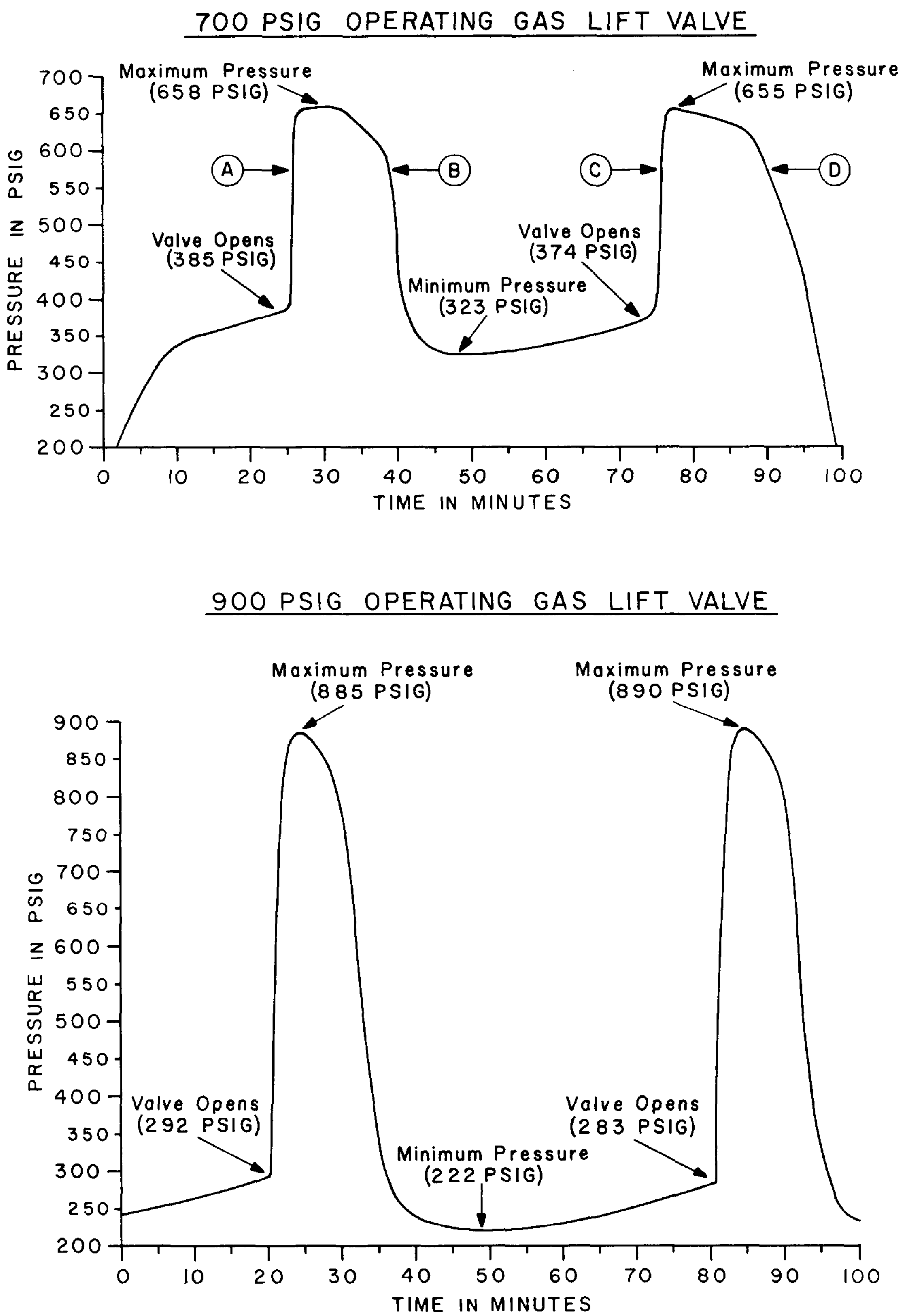


FIG. 8

PRESSURE SURVEYS ABOVE STANDING VALVE AT 6580FT. IN A CHAMBER INSTALLATION the bomb; and the tubing must be pulled in order to recover the bomb.

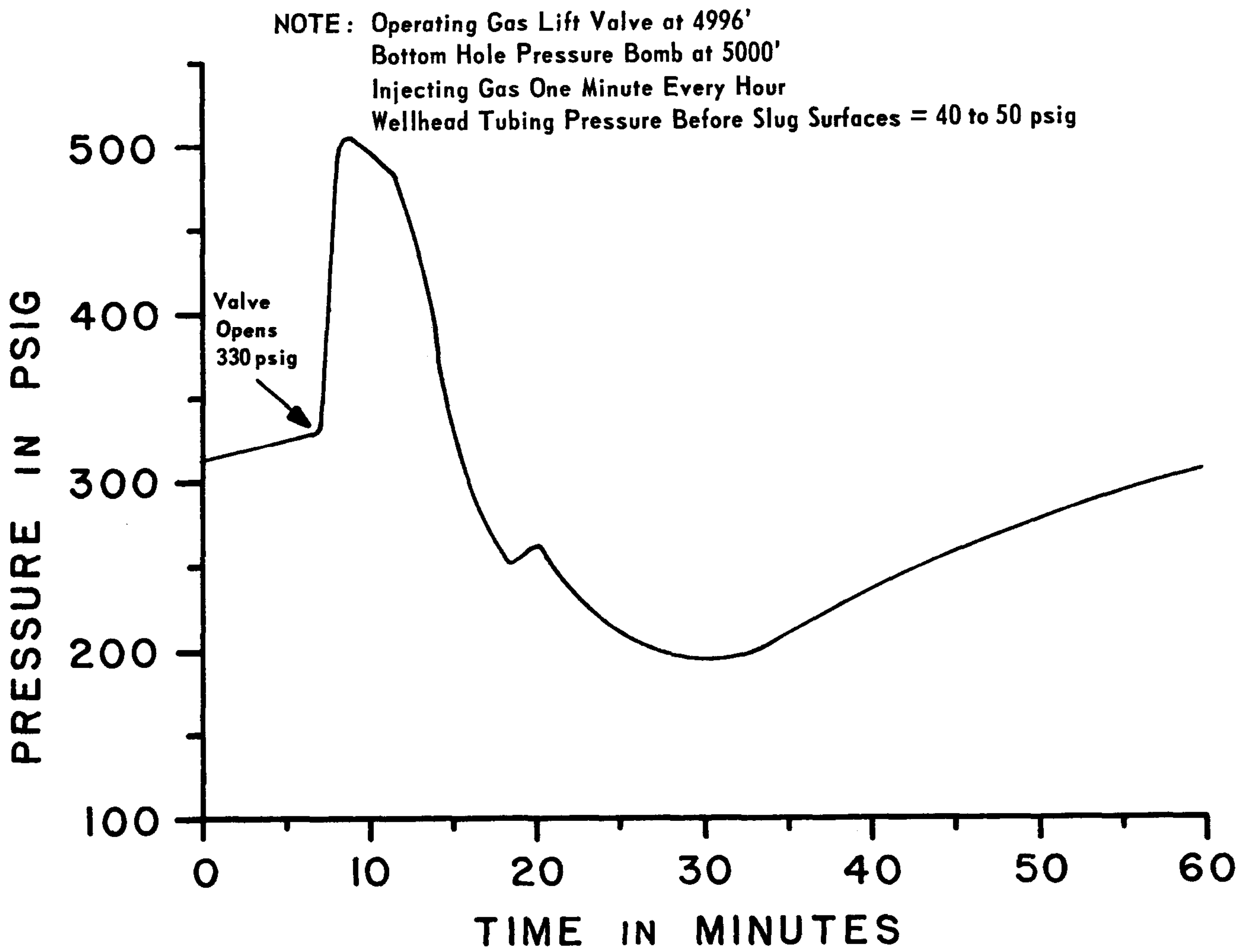
Another method was employed for surveying in intermitting wells for several of the surveys presented in this paper. A heavy, small O.D. two-section stem was run above the bomb. To increase the weight per unit length, a hollow stem filled with lead was used. The stem can be made heavier by using mercury instead of lead. The stem O.D. was slightly less than the diameter of the bomb (1-1/4 inch O.D.). The disadvantage of using a special stem is the additional required length of lubricator. The lubricator used to run the bomb and special stem is shown in Fig. 3.

Smaller tubing sizes require increased precaution. As the slug surfaces, the pressure is reduced and the space occupied by the gas increases, thus causing higher velocities. The clearance between the bomb and tubing is much less in 2 inch tubing than in 2-1/2 inch tubing. Initial surveys in intermitting wells should begin at the maximum depth to be recorded below the gas lift valves. The survey should be continued above each succeeding higher valve until significant line jerk is felt at the surface. Since the bomb is obviously above the operating gas lift valve, the survey should be discontinued.

LOCATING OPERATING VALVE

An intermitting gas lift well being produced by a high injection gas cycle frequency represents one of the most difficult types of gas lift wells in which to locate the operating valve. This category well is usually between an intermitting well and a continuous flow well. The point of gas injection is too deep for efficient continuous flow; therefore, the well is intermitted as rapidly as possible for maximum production. Generally, a temperature survey is more quantitative than a pressure survey for locating the operating gas lift valve.

Pressure and temperature surveys conducted in the same well on the same day are shown in Fig. 4. The surface controller on the injection gas line was open for 2-1/2 minutes once every 10 minutes (144 injection gas cycles per day). The curves in Fig. 4 represent nearly 400 readings and are included to illustrate the appearance of bomb charts obtained from these surveys. For interpre-



PRESSURE SURVEY IN INTERMITTING WELL FOR ESTIMATING PER CENT LIQUID FALL-BACK tive purposes, only the maximum and minimum values recoreded at each depth are needed, as shown in Fig. 5.

It is difficult to determine the operating valve from the pressure survey in Fig. 5. The operating valve was obvious in the temperature survey. Although a small volume of gas was entering the gas lift valve at 5025 feet, the valve at 4534 feet was the operating valve. The pressure survey indicated the operating valve to be at 5025 feet which was not true since most of the gas was entering the tubing at 4535 feet.

LOCATING HOLE IN TUBING OR LEAKY VALVES

Tubing leaks, cutout gas lift valve seats, and packer leaks are indicated by a continual decrease in injection gas pressure after the injection gas is hut off and the operating valve has closed. In an intermitting well, the injection pressure in the casing will not remain equal to the surface closing pressure of the operating gas lift valve between gas injections. Instead, the casing pressure continues to decline until the time cycle surface controller reopens for the next injection gas cycle. Temperature and pressure surveys can be used to locate a leak in the tubing string which includes leaky gas lift valves.

Locating Hole in Tubing with Pressure Survey

The flowing pressure survey in Fig. 6 was conducted in a continuous flow gas lift well. The injection gas-liquid ratio had increased in a metter of weeks from 270 to 550 cubic feet per barrel for the same producing rate. Leaky valves were suspected prior to running the survey. However, a tubing leak was located at 2070 feet. The pressure traverses plotted in Fig.-6 are average gradients based on the pressure survey. Numerous stops were required to establish the average gradients and pin point the leak.

Locating Leaky Valves with Temperature Survey

A temperature survey conducted in a deep intermitting well is shown in Fig. 7. The injection gas pressure in the casing would continue to decline until the time cycle surface controller reopened; therefore, leaky gas lift valves were suspected. Gas lifting of the well was continued until the temperature bomb was ready to be lowered in the well so that injection gas would enter the tubing during the survey. The injection gas must enter the tubing at the leak or leaks before these gas entry points can be located. At each leak there is a cooling resulting from the expansion of the injection gas after it enters the tubing.

The temperature bomb was stationed from 10 to 25 feet above and below each gas lift valve. Generally, the temperature element requires a longer period than a pressure element at each station for stabilization. The temperature survey indicated that three valve seats were leaking, as shown in Fig. 7. The gas lift valves were pulled and tested. Only three valves were found to be leaky and these were the same valves indicated by the survey. The valve at 6875 feet was immediately above the fluid level, which accounted for the greater cooling effect due to a greater differential pressure across the valve seat.

ANALYZING GAS LIFT INSTALLATIONS

Chamber Installations

Two bottom hole pressure surveys for the same chamber installation are shown in Fig. 8. This is a two packer chamber in 5-1/2 inch O.D.casing. The well is being lifted from nearly 6600 feet through 2 inch tubing. The bomb was stationed immediately above the standing valve at the bottom of the chamber.

During the first survey the operating valve had an opening pressure of 700 psig. The pressure build-up curve after the valve opened was flat and wide (between points A and B and points C and D) which indicated the fluid load in the chamber was near the opening pressure of the operating valve. The well was producing approximately 115 barrels of total fluid per day (11 barrels of water) with an injection gas-liquid ratio of 2355 cubic feet per barrel.

The operating valve was replaced with a 900 psig opening pressure gas lift valve prior to running the second survey. The higher pressure valve increased the production rate to 153 barrels of total fluid per day (67 barrels of water) with an injection gas-liquid ratio of 1445 cubic feet per barrel. The increased water percentage occurred during the nine months between the two tests.

These bottom hole pressure surveys illustrate the importance of designing a chamber installation for adequate differential between the injection gas pressure and the maximum pressure required to unload the chamber. Although the maximum pressure build-up in the chamber after the valve opened was greater with the higher pressure gas lift valve, the lower minimum drawdown and increased recovery indicated a significant increase in operating efficiency. Adequate differential pressure reduced the fall-back although the water percentage had increased.

Fall-back in Intermitting Wells

Many times it is desirable to determine the per cent of liquid recovered in relation to the total initial fluid head above the gas lift valve at the instant the valve opens. A typical pressure survey in a 5200 foot well on intermitting gas lift is shown in Fig. 9.

The operating gas lift valve is located at 4996 feet and the bomb was stationed at 5000 feet for the survey. The time cycle surface controller on the injection gas line was open one minute each hour. The well was producing approximately 1.3 barrels per cycle through 2 inch tubing. From the pressure survey in Fig. 9, the pressure in the tubing above the valve at the instant the valve opened was 330 psig. Subtracting the pressure due to wellhead tubing back pressure, the initial fluid column above the valve would represent approximately 3.5 barrels (measured static fluid gradient — 0.31 psi per foot in this well). Therefore, the per cent recovery was 37 per cent and the fall-back was 63 per cent.

This type of data is valuable for selecting the proper injection gas cycle frequency and length of injection for minimum fall-back, predicting maximum producing rates by intermittent lift for similar well conditions, evaluating injection gas pressure in relation to fall-back, etc.

CONCLUSION

A pressure survey before the installation of gas lift equipment represents a small expenditure which can save the operator many dollars. The savings may be in initial equipment or higher operating efficiency from a properly designed installation, or both. The pressure element range employed for a survey should be compatible with the pressure to be measured. In other words, a 0 to 6000 psig range element should not be used to measure 300 psig.

A fast chart drive clock should be used in the bomb for temperature and pressure surveys for detailed analysis of gas lift operation. A six-hour drive chart was used to obtain the surveys shown in Fig. 4, and a three-hour clock was used to obtain the surveys shown in Fig. 8. Certain precautions are required when running a survey in a gas lift well being produced by intermittent lift. The use of the temperature survey for quantitative work in gas lift wells is overlooked by many operators.