Analysis Of Gas Lift Installations

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INTRODUCTION

A common error in utilizing gas lift as a means of artificial lift is the failure to properly analyze the completed installation. This, of course, has resulted in low efficiencies and poor operations. Quite often the operator finds that excessive gas is being used or that production is low on a particular lease. However, it may be that a complete analysis of required injection gas has never been made. A common tendency for the field operator is to increase injection gas rates in an attempt to move more oil from the well. This may actually result in decreased production.

METHODS USED

There are numerous methods of properly analyzing a gas lift installation. These apply to both continuous flow and intermittent flow. Some of these are listed as follows:

1. Pressure survey
2. Flowing temperature survey
3. Fluid level determination by acoustic methods
4. Recording of both casing and tubing pressures
5. Total fluid recovery
6. Injection gas volumes
7. Total output gas volumes
8. Flowing tubing pressures
9. Miscellaneous

Pressure Survey — Continuous Flow

It is believed that the pressure survey offers the best means of properly analyzing both continuous flow and intermittent flow installations.

A common fallacy in running flowing pressure surveys is to wait until some trouble develops. Admittedly, the trouble can more than likely be located, but vital information as to how to improve the installation will not be obtained. The importance of the correct spacing of gas lift valves on high PI continuous flow wells cannot be overemphasized. Therefore, a pressure survey should be run while the well is supposedly performing satisfactorily. This type of information will in turn allow a correct respacing of gas lift valves.

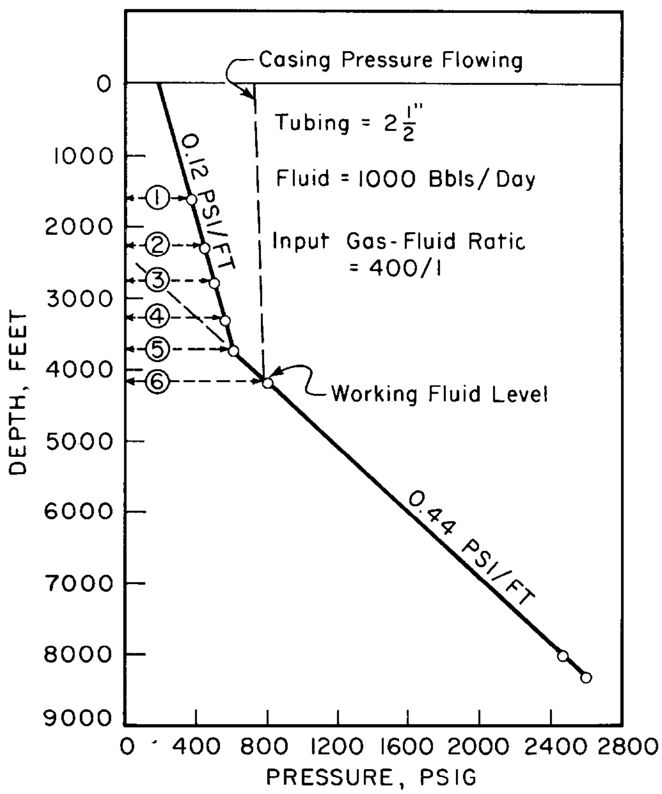
A very common error on valve spacing is the failure to space valves close enough together. On wells producing from a very active water drive and having high PI's, it is advisable to space valves as close as two or three tubing joints apart (60 to 90 feet). Reference should be made to Fig. 1, which shows a well making 1000 bbls. per day of oil and water (90 per cent water). From all surface indications the well was performing satisfactorily. However, from the flowing pressure survey it was immediately evident that a change in valve spacing should greatly increase total fluid production. It is noted that the fluid level in the casing lacks only a few feet of uncovering the last valve with the available line pressure. Since this well had a PI of 10 or greater, the valves were respaced by placing the last valve at a position whereby it could be operated (approximately 60 feet back up the string).

By checking the static fluid level it was possible to relocate valves Nos. 1 and 2 as the last two valves in the string and to space them three and two tubing joints apart respectively. The production rate on this well was increased to 1600 bbls. per day. Since this was an active water drive with the field showing very little drop in pressure with time, the spacing was satisfactory for one and one-half to two years.

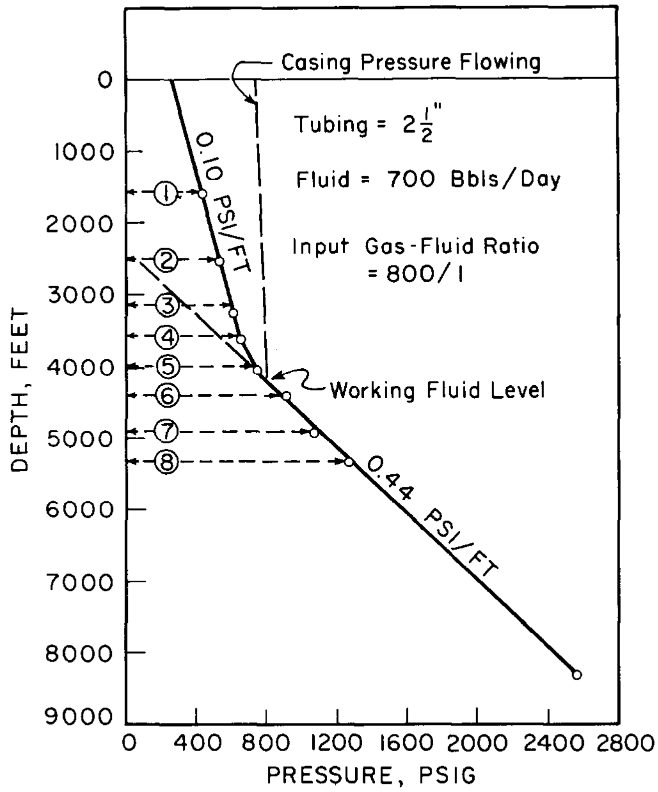
Fig. 2 shows a well where two or three gas lift valves are admitting gas, showing valve interference. A check on the flowing gradient above the point of gas injection indicates that too much gas is being injected. This was also confirmed by a measurement of the input injection gas-liquid ratio of 800/1 as compared to 400/1 for the well of Fig. 1. There does not seem to be a need for respacing valves on this well, but a need for repairing valves 3 and 4. Valves 6, 7 and 8 could be grouped closer to the annulus working fluid level (point to which the available casing pressure depresses the fluid in the annulus).

Fig. 3 shows a gas lift installation where too many valves have been run in the well. Four valves would be enough to take care of this well under present conditions. However, if this were a well in which water percentages were expected to increase considerably, thereby resulting in a lower annulus working fluid level, the utilization of lower valves would be justified. An input gas oil ratio of 150/1 indicates a very efficient installation.

Another very useful purpose of flowing pressure surveys is to locate a leak in the tubing. This is very easily noted

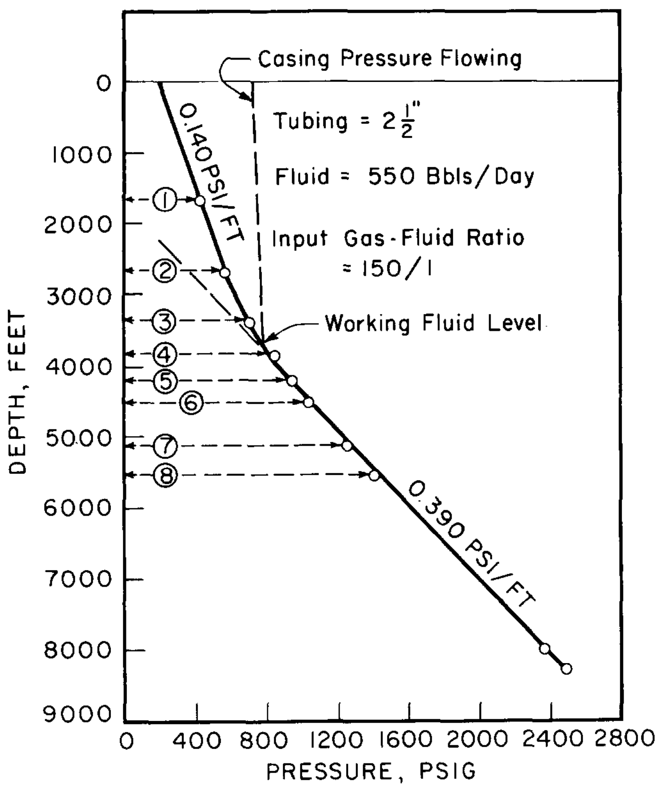


FLOWING PRESSURE SURVEY
FIG. 1



FLOWING PRESSURE SURVEY

FIG. 2



FLOWING PRESSURE SURVEY

FIG. 3

by an abrupt change in gradient at the point of the leak (Fig. 4). Leaking gas lift valves can be detected in the same manner.

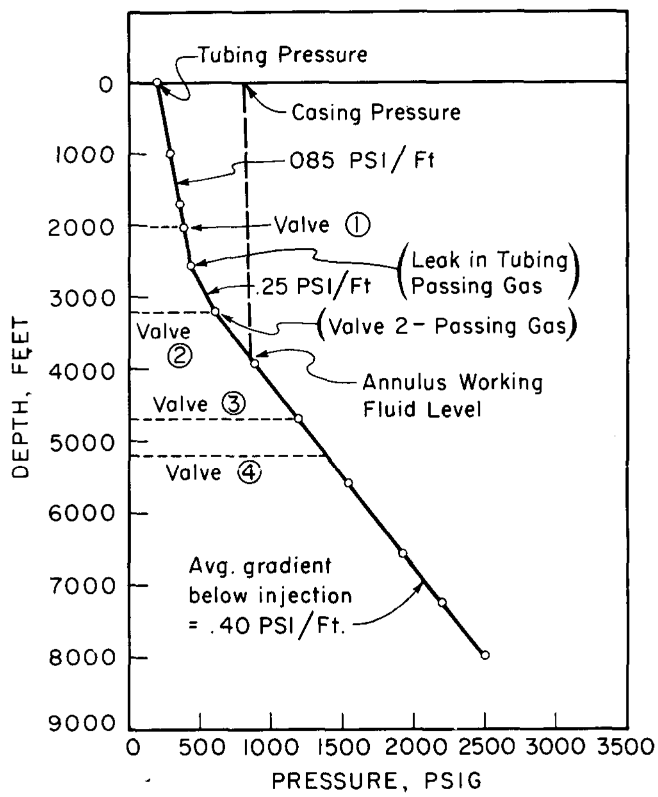
Some precaution should be exercised in running flowing pressure surveys. The well should be prepared on the day prior to the survey by placing the lubricator for the pressure bomb in place with an additional master valve above the flowing valve. This allows a pressure survey to be run without having to shut the well in. This is important since complete stabilized flow is a necessity.

It may also be necessary to run a lead or mercury weighted section on the bottom of the pressure bomb to minimize the possibility of losing the instrument. In some wells it may even be necessary to shut the well in, run the bomb to bottom as fast as is practical, and then start the well to flowing. After the well has again stabilized, the survey can then be started up the hole. Since the highest fluid velocities occur near the top of the tubing string it is very likely that the survey can be completed except for the last 200-300 feet of the string.

The wire line operator can detect a slackening in the line at the point where the fluid velocities are trying to pick up the bomb. The important section of the tubing string (above and below the point of gas injection) will have been surveyed successfully. It is a good idea to stop every 500 to 1000 feet below the point of gas injection to establish the gradient in that region of flow, and then stop approximately 10 feet below each gas lift valve above the point of gas injection. This would assure a correct location of the operating gas lift valve, as well as valve leaks.

Intermittent Flow

The running of a flowing pressure survey in an intermit-



TUBING LEAK LOCATED BY FLOWING PRESSURE SURVEY

FIG. 4

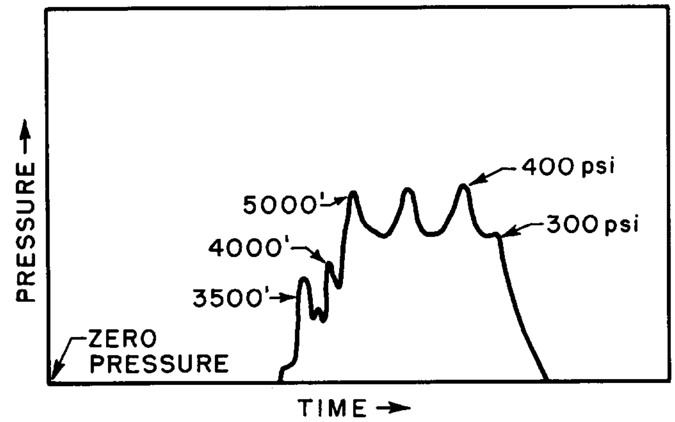


FIG.5. TYPICAL FLOWING PRESSURE SURVEY FOR INTERMITTENT GAS LIFT OPERATION.

tent installation, and in particular one that is lifting from bottom or from a chamber, offers more of a problem than does running a survey on a continuous flow well. However, if the bomb can be run beneath the operating valve or placed on a bomb hanger (tool to hold the recording pressure gauge in place) there is then no danger of blowing the bomb up the hole.

Some very valuable information can be obtained from a pressure survey in an intermittent well. The pressure buildup between cycles, as well as the bottom hole pressure immediately after each cycle, can be obtained. By knowing the position of the operating valve the amount of slippage or fall-back can be determined. In turn, an average draw-down can be established for a particular well allowing PI calculations. A pressure buildup curve can also be obtained.

Reference should be made to Fig. 5 which shows a typical pressure survey as conducted in an intermittent flow well. For this particular well, the survey substantiated a partial water block since the survey showed the well to be producing from the bottom valve, and making very little total fluid.

Flowing Temperature Surveys

A flowing temperature survey can be valuable in locating tubing leaks as well as locating the operating gas lift valve. However, a flowing temperature survey is not as valuable as a pressure survey. Therefore, in most instances it would be preferable to run a pressure survey because it will pick up valuable pressure gradient information, which, in turn, will allow PI calculations from draw-down information. The pressure survey will also locate the tubing leak easily on continuous flow wells, but with possible difficulty on intermittent wells.

Fluid Level Determined by Acoustic Methods

A very fast means of determining the fluid level in the annular space is by sounding the well. This is an acoustic device whereby the fluid level can be easily detected by utilizing very simple surface connections. This is a very easy method to pick up a fluid level, thereby checking on the operating valve. However, extreme caution should be used in wells containing a packer. It may be that the well originally unloaded to the bottom valve, and later a valve up the hole lost some of its original charge.

Although the acoustic device would show the well unloaded to the last valve, it could be possible that a valve back up the string would actually be the operating valve. Also, many wells originally placed on lift will require additional drawdown in the first stages of lift, thereby unloading the annular space of fluid. These same wells, after several days of production from a lower valve, may then operate from a valve higher up the string.

The acoustic device would be very well suited for continuous flow installations without a packer. The annular working fluid level could be easily detected in this manner. Therefore, a valve losing pressure and causing the fluid to rise to that point could be easily detected. It would be more satisfactory to take periodic soundings and, in particular, one sounding when the well is performing satisfactorily. This would allow for comparisons of changing fluid levels.

Also for intermittent wells without a packer, where it is known that the well should be operating from the bottom valve, this could be an immediate check. If the fluid level has moved back up the string, a valve pressure loss could be suspected. A packer is normally run on an intermittent well and the lowest fluid level attained during the artificial lift period would be the level determined with the sounding device.

Reference should be made to Fig. 6 for a typical acoustic survey.

Recording of Both Casing and Tubing Pressures

One of the most economical means for keeping an accurate check on the behavior of a gas lift well is to obtain daily recordings of both the tubing and casing pressure. It is the recommendation of the authors that a two-pen recorder be placed on every gas lift well. Many improving adjustments of surface controls can be made after a careful study of two-pen recording charts. These charts are applicable to both continuous and intermittent flow. If the

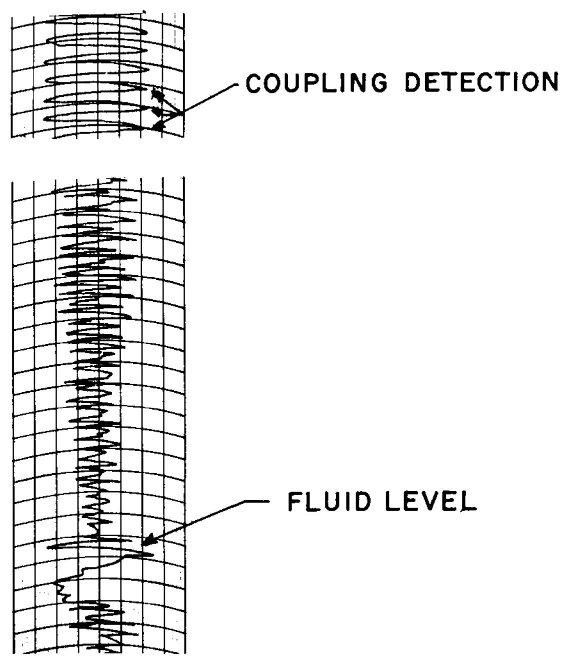


FIG. 6. TYPICAL WELL SOUNDING SURVEY.

$2\frac{1}{2}$" TUBING

7" CASING

recorder is placed on the well as soon as valves are installed, the actual unloading of the well, as it lowers from valve to valve, can be observed on the chart.

Some of the important factors to be noted from a record of the tubing and casing pressure are:

1. Increased surface flowing tubing pressures would indicate scale or paraffin deposition in the flow lines or possibly in increased trap pressures.
2. A continuous flow well on tubing control could start flowing from its own power and this would be noted from the charts.
3. The changing from one operating valve to another could be detected.
4. The sanding up or water blocking of a well
5. Leaking gas lift valve
6. Leak in the tubing
7. Too long or too short injection cycle for intermittent flow
8. Excessive fall-back or slippage in intermittent flow
9. Excessive gas usage
10. Decreased production
11. Inefficient operation

The following chart examples will serve to illustrate some of these factors.

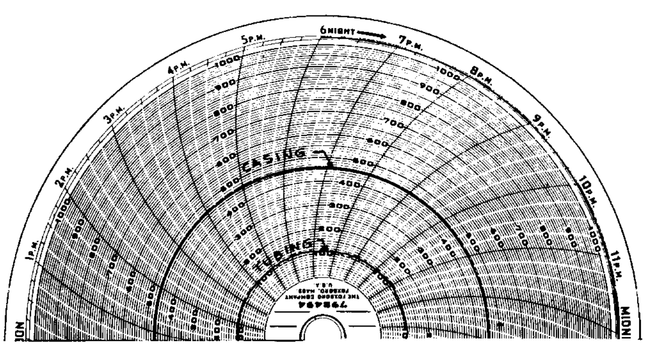
Reference should be made to Charts 1 through 19. It should be pointed out that the actual problems and troubles encountered are the ones given in the interpretations. It is certainly possible that other interpretations could be given if the exact trouble were not known.

Total Fluid Recovery

A very important method of analyzing wells is the maintaining of proper production records. One of the first indications of a troubled installation, of course, is a loss in oil and/or total liquid production. This means of analyzing a well is self-explanatory and should require no further comments.

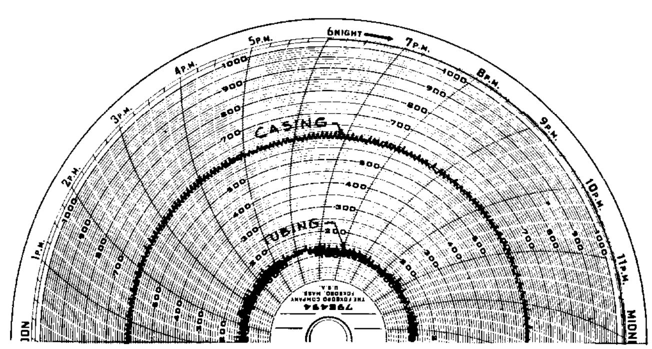
Injection Gas Volumes

Every well on gas lift should be equipped with a meter for measuring injection gas volumes. At least a meter flange should be installed so that a portable meter could be used for spot-checking the gas being used. Normally, a continuous flow well will offer no problem in gas measurement. However, a well on intermittent flow will make recordings on a gas meter chart that are difficult to interpret.



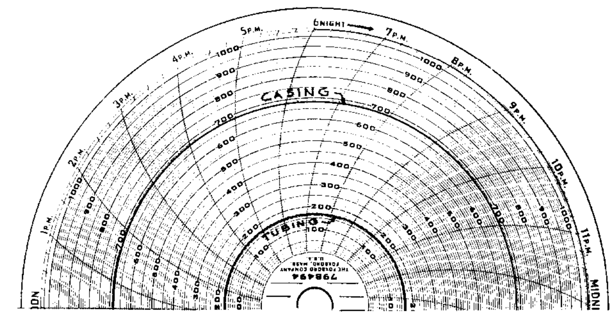
OPERATION — Continuous Flow
TROUBLE — None
REMARKS — Good Operation

CHART I.



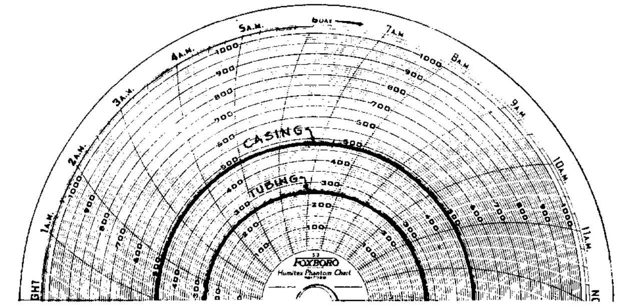
OPERATION — Intermittent-Continuous Flow
TROUBLE — None
REMARKS — On constant injection well fluid emulsified, on short intermittent injection the emulsification ceased.

CHART 2.



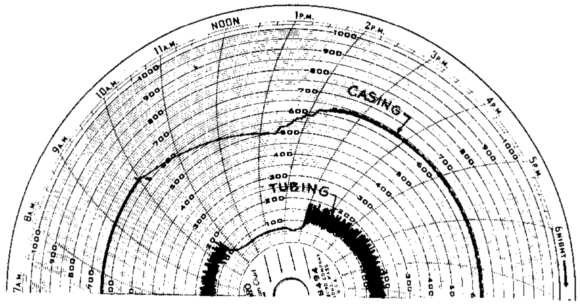
OPERATION - Continuous flow
TROUBLE - None
REMARKS - System should be investigated for possibilities of lowering the flowing tubing pressure if additional production is desired. Gas injection by choke at surface.

CHART 3.



OPERATION - Continuous flow
TROUBLE - Low production
REMARKS - System should be investigated for excessive back pressure. Gas injection by choke at surface.

CHART 4.

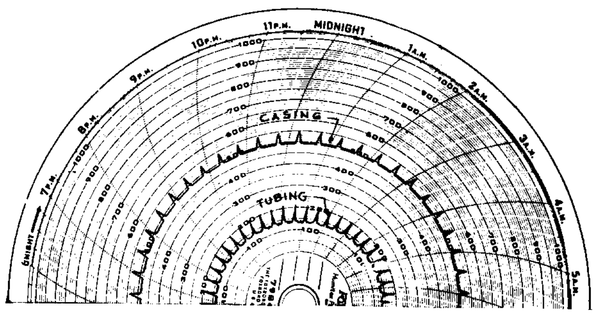


OPERATION — Continuous Flow — Tubing Controlled Injection

TROUBLE — Freezing in injection gas line.

REMARKS — Freezing of injection gas line and subsequent lowering of casing pressure indicated a leaking valve. (Not serious) Line thawed out and well again stabilized.

CHART 5.

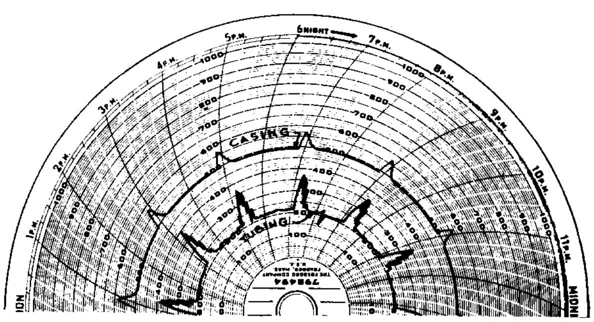


OPERATION — Intermittent Lift

TROUBLE — None

REMARKS — Good Operation

CHART 6.

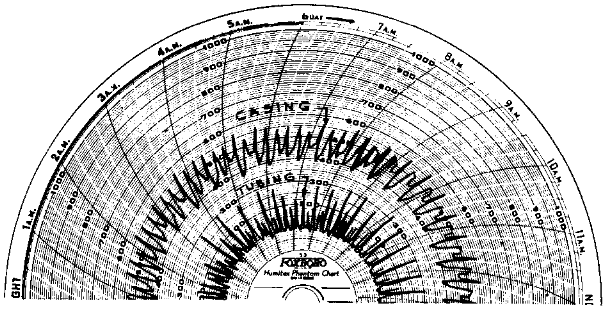


OPERATION - Intermittent Lift

TROUBLE - Cycles too long.

REMARKS - Well should be capable of producing more fluid on shorter cycles. Well heading at end of slug indicating excessive fall-back of fluid. Reason for high trap pressure should be determined.

CHART 7.

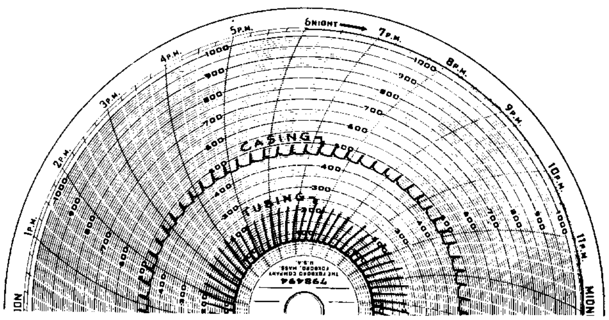


OPERATION - Intermittent Lift

TROUBLE - Alternating valve operation with lower valve leaking, or tubing leak below upper valve.

REMARKS - Longer cycling might prevent injection at the lower point of operation.

CHART 8.

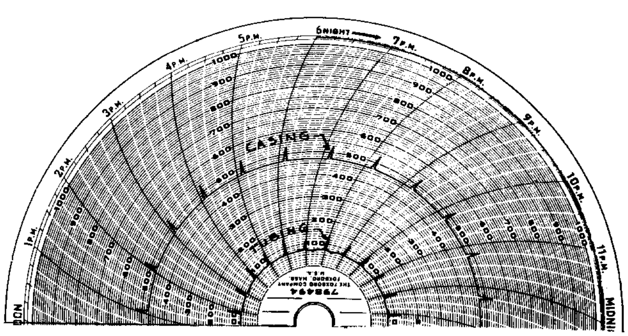


OPERATION — Intermittent Lift

TROUBLE — None

REMARKS — Good Operation

CHART 9.

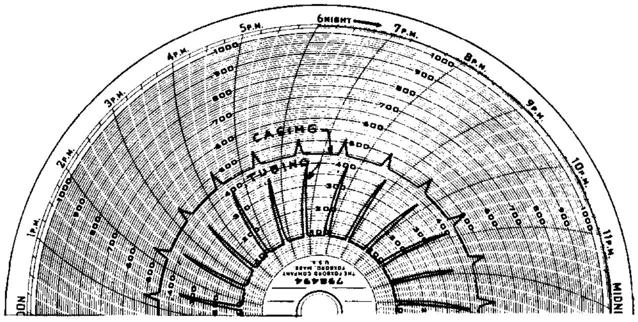


OPERATION - Intermittent Lift

TROUBLE - None

REMARKS - Good operation - Low productivity well.

CHART 10.

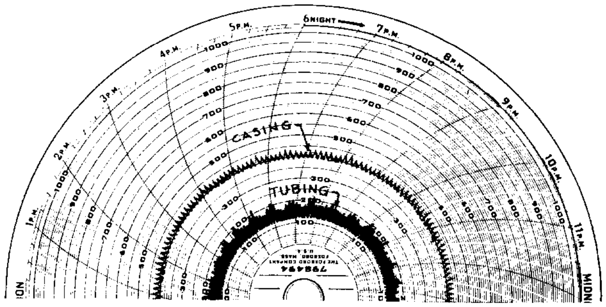


OPERATION – Intermittent Lift

TROUBLE – None

REMARKS – Deep lift (8000 ft.). Tree should be examined for possibility of eliminating high maximum tubing slug pressure.

CHART 11.

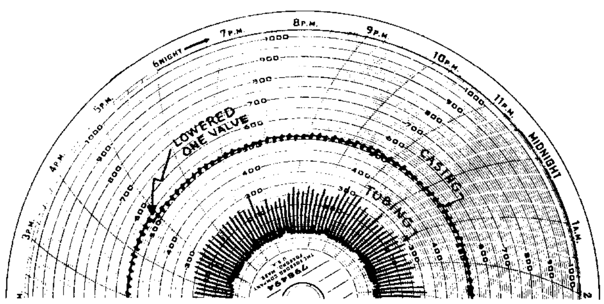


OPERATION – Intermittent Lift

TROUBLE – None

REMARKS – Ten minute cycle for producing at maximum rate on a high productivity, low bottom hole pressure well.

CHART 12.

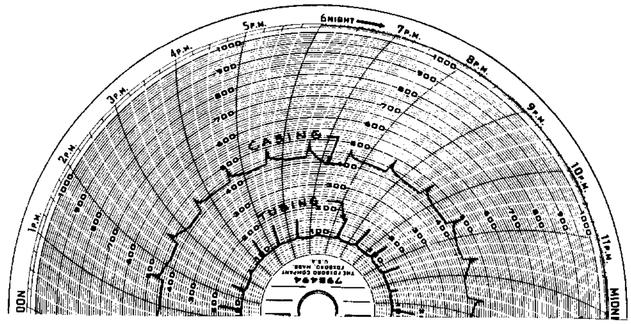


OPERATION — Intermittent Flow

TROUBLE — None

REMARKS — Well lowered one valve as indicated by a drop in casing pressure.

CHART 13.

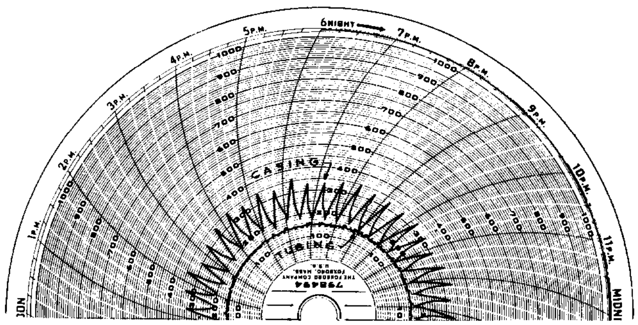


OPERATION – Intermittent operation

TROUBLE – Valve leaking and alternating valve operation.

REMARKS – A shorter cycle will maintain lower valve operation. If valve leakage is too bad, valve will have to be replaced.

CHART 14

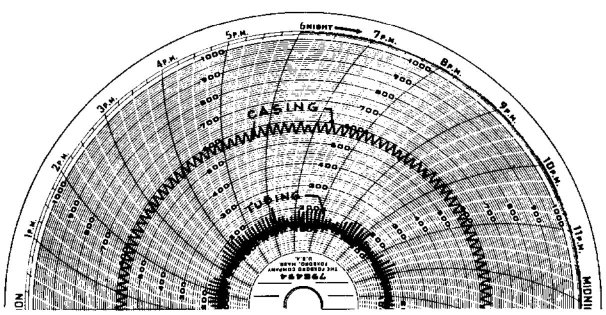


OPERATION – Intermittent Lift

TROUBLE – Gas lift valve cut out, or tubing leak.

REMARKS – Not making production, blowing dry gas.

CHART 15.

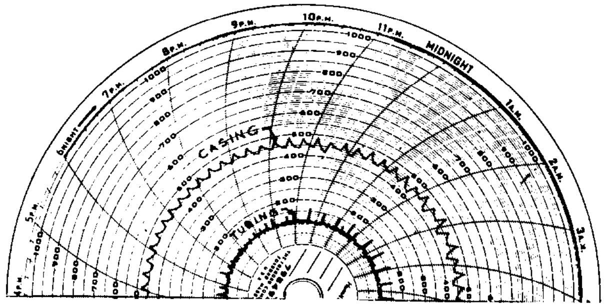


OPERATION - Intermittent Lift

TROUBLE - Gas lift valve cut out or tubing leak.

REMARKS - This is indicated by casing pressure failing to stabilize.

CHART 16.

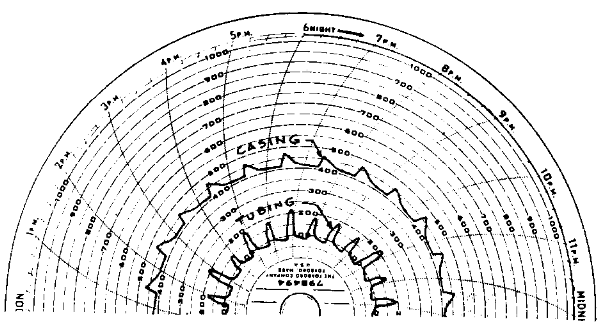


OPERATION – Intermittent Lift

TROUBLE – Questionable

REMARKS – Operation alternating between two valves. For greater fluid recovery, shorten injection cycle to maintain lower valve operation. If well is making allowable, operation satisfactory.

CHART 17.

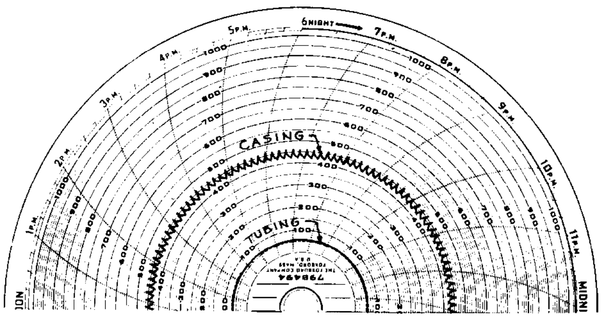


OPERATION – Intermittent Lift

TROUBLE – Tubing restriction, or injection cycle too long.

REMARKS – Remove restriction from tubing or wellhead, or try a shorter injection cycle

CHART 18.



OPERATION – Intermittent Lift

TROUBLE – Well sanded up.

REMARKS – Well blowing dry gas from deep injection point.

CHART 19.

This is particularly true for a 24-hour or 7-day revolution clock. Therefore, provisions should be made to obtain combination clocks on the gas meters that can be easily converted to 24-minute clocks (one complete revolution in 24 minutes).

The gas injected per cycle should be recorded on this 24-minute chart; in turn, enough separate "kicks" on the chart should be obtained to secure an average reading. The gas used per cycle can then be calculated. The total number of kicks per day may be counted from the 24-hour chart or obtained from the injection clock settings. By multiplying the gas used per cycle by the number of cycles per day a very close approximation can be obtained for the injection gas-liquid ratios.

Again, this is information that should be obtained periodically so that an immediate increase in gas consumption can be detected. There can be any number of reasons why gas consumption would increase. For example, a continuous flow well on casing control (constant gas pressure maintained at surface) might lower itself down to the next lower operating valve. The casing pressure would then attempt to adjust itself to the lower valve setting, but the regulator at the surface would attempt to maintain a constant higher casing pressure. This would result in high gas consumption with the operation of two or more gas lift valves.

Other troubles would be a leak in the tubing, leaking packer, leak in the Christmas Tree pack-off, etc.

Total Output Gas Volumes

In addition to measuring input injection gas, provision should be made for metering the total gas being produced by the well. This in turn allows a check on the input gas injection meter since the output meter will be measuring injection gas plus produced reservoir gas. This is important because a well in later stages of production may exhibit a decided increase in produced gas. This gas must be considered since it is performing work on continuous flow wells and may result in a decided decrease in input injection gas. Integrating instruments should be considered for gas meters where gas volume calculations become difficult.

Flowing Tubing Pressure — Continuous Flow

The flowing tubing pressure is an extremely important factor in controlling total fluid production.

In continuous flow, the tubing pressure directly influences the bottomhole pressure drawdown. For high PI wells an increase in tubing pressure of 100 psi could result in a decreased production of several hundred barrels per day. Again a periodic check should be taken on tubing pressures. Any immediate increase in flowing tubing pressure should be investigated. This increase could be caused by small flow lines, restricted flow lines, surface chokes, paraffin or scale depositions. If maximum production is desired, the Christmas Tree should be streamlined, and all sharp bends taken out of the tree and flow lines.

If necessary, the surface flow line should be exchanged for a larger line. If the surface flow line is of such length that the tubing pressure is materially influenced, consideration should be given to the possibility of installing a tubing flow line booster. This can be very conveniently arranged by installing an enclosed gas lift valve on the surface flow line and using gas pressure to boost flow.

Another important consideration is that in the lower range of gas expansion the greatest amount of work is expended.

The following charts (Refer to Charts 20, 21, 22, 23) are offered to emphasize the difference in gas volumes and gas injection pressures needed to produce the same well against back pressures of 50, 100 and 200 psi respectively.

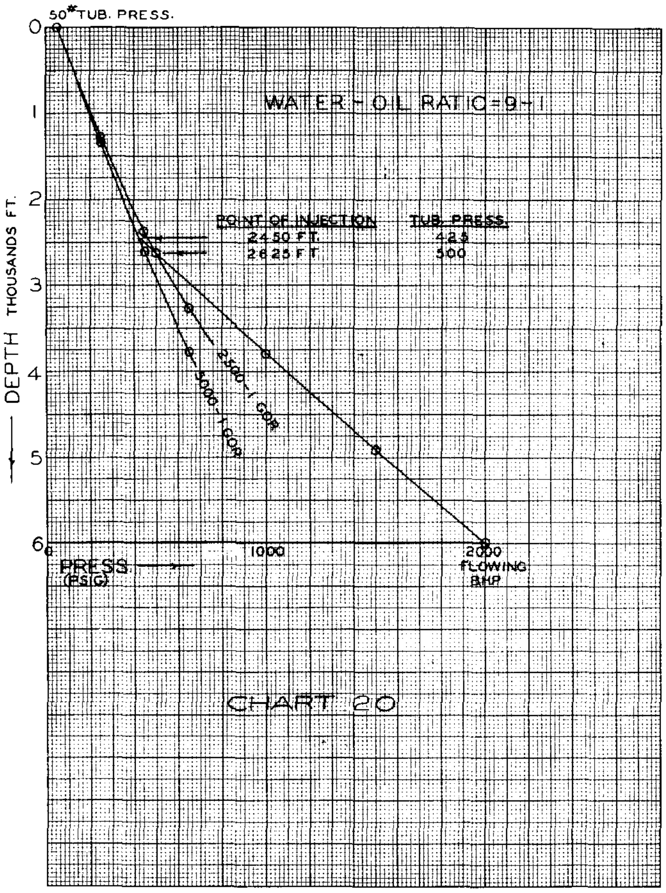


CHART 20

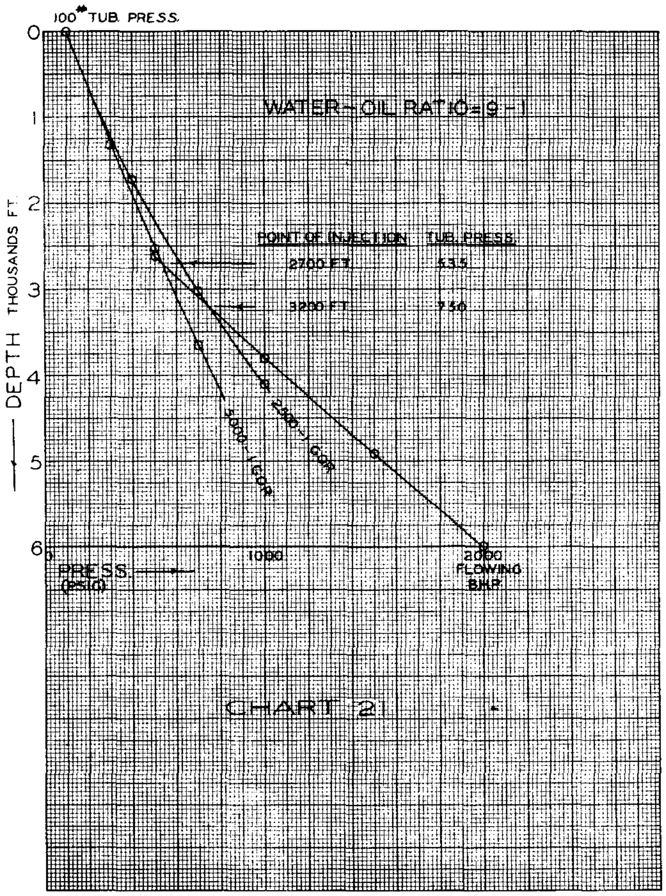


CHART 21

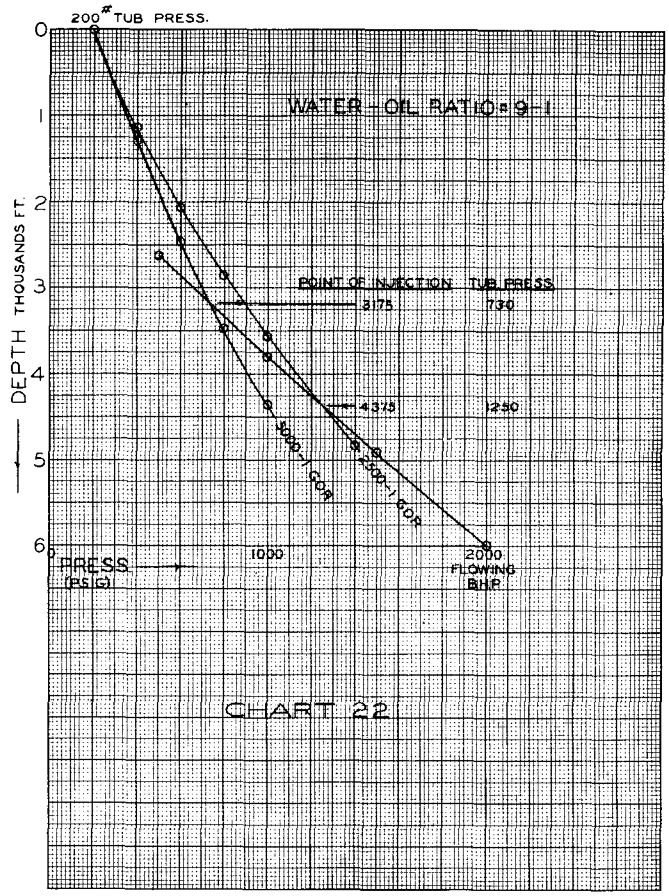


CHART 22

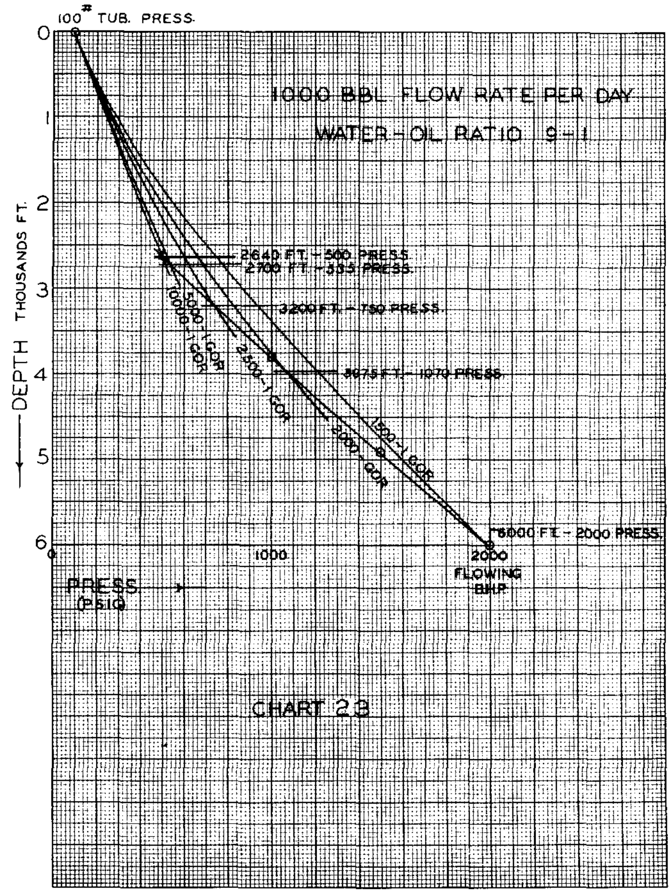


CHART 23

These illustrations show the effect of having to produce the same amount of fluid (creating the same flowing bottomhole pressure of 2000 psi) against the three different tubing pressures. In order to further illustrate the effect of back pressure and gas injection volumes, an injection gas oil ratio of 2500/1 and 5000/1 were both used to calculate a flowing gradient above the point of gas injection.

The following tabulation summarizes the important factors that should be noted from these three charts.

Chart	Wellhead Tubing Pressure	G.O.R.	Depth to Point of Injection	Tub. Pres. at Point of Injection	Surface Casing Pressure Required
20	50	2500-1	2625	500	525
		5000-1	2450	425	450
21	100	2500-1	3200	750	750
		5000-1	2700	535	550
22	200	2500-1	4375	1250	1190
		5000-1	3175	730	730

It is interesting to note that on a 2500-1 GOR with a 50 psig wellhead tubing pressure, the point of injection is at 2625 feet, with a surface casing pressure of 525 psig; while on a wellhead tubing pressure of 200 psig, the point of injection is at 4375 feet, with a surface casing pressure of 1190 psig.

It is immediately evident that additional horsepower requirements are necessary to obtain the same production from this well for variable surface back pressures.

As a matter of interest, Chart 23 shows the reduction in gas volumes necessary as the point of gas injection is lowered. This is for a production rate of 100 bbls. of oil and 900 bbls. of water per day. The importance of higher injection pressures cannot be overemphasized. In analyzing any well consideration must be given to the injection gas pressure. In many instances it is impossible to increase total fluid recovery without increasing the injection gas pressure.

Intermittent Flow

High back pressure can be expected to retard production on low bottom hole pressure wells. This can be very critical on wells having only 150-200 psi bottomhole pressure. If this is a high PI well, a decrease in back pressure of only 5-10 psi may cause a noticeable increase in production. It is then almost imperative that trap pressure be kept to a minimum on low bottomhole pressure, high PI wells.

For wells with long flow lines that require some choking at the surface to prevent severe surges on the separator, excessive fall back of fluid may be encountered. A wise trick is to place the choke, if one is necessary, at the end of the flow line immediately upstream from the separator. This allows the flow line to serve as a volume chamber preventing excessive fluid fall back.

Miscellaneous

There are various well manipulations that can be performed and well conditions that can be checked at the surface to help in analyzing a well.

On continuous flow wells that normally produce hot fluid to the surface, an immediate cooling of the flow line indicates a lack of fluid entry or too much gas injection. By merely feeling of the flow line on a continuous flow well, any drastic reduction in production is noted.

A very simple well check will also indicate whether or not tubing leak or a gas lift valve leak exists. The tubing pressure is equalized with the casing pressure by means of a bypass or by closing the tubing wing valve. Pressure is then decreased on the casing by bleeding off gas.

If the tubing gauge indicates a drop in pressure, it is likely that a tubing leak exists. However, if no drop in pressure is noted on the tubing gauge it is then indicated that a gas lift valve is leaking. This test would only be valid if all reverse checks were sealing properly. A leaking valve with a reverse check failing to hold would also behave similar to a tubing leak for this test.

CONCLUSIONS

The proper analysis of a gas lift well may result in tremendous savings for the operator by decreasing injection gas volumes required and increasing total oil recovery. All wells should be completely analyzed while they seem to be performing satisfactorily. In particular, flowing pressure surveys should be considered. Although a change in valve spacing may not be economical at the time of the survey, valuable information will be obtained which can be utilized if and when the tubing is pulled.

The use of two-pen recording charts cannot be overemphasized. Once a person becomes skilled in analyzing these charts, trouble can immediately be detected without making a trip to the well. Many operators determine when correcting adjustments are necessary by merely keeping a daily record of recording charts. Such things as increased back pressure and leaking tubing and/or valves is immediately detected.