Prediciting Plunger Lift Performance

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INTRODUCTION

Plunger lift excels at producing high GLR oil wells and removing liquid accumulations from gas wells. As reservoirs deplete and flowing rates decline, the gas phase becomes less efficient at lifting the liquid phase to the surface. Allowed to continue, the flowing gradient will become heavier until the well loads up with liquid and stops flowing.

In gas wells, smaller tubing (siphon tube), a compressor, rod pumping, or plunger lift is installed to maintain flowing status. Neither the smaller tubing nor a compressor is a permanent solution. They increase the gas velocity initially so that the liquid will be carried out; however, at some time in the future the gas rate will again fall to an inadequate level and the liquid will not be removed from the well. Rod pumping is a permanent solution but an expensive one. Plunger lift provides a permanent solution like rod pumping, however, and at a lower price than any other method. Another alternative is a subsurface liquid diverter. A comparison of plunger lift and the subsurface liquid diverter will be presented in the section on intermittent gas lift.

In oil wells, plunger lift may be installed in lieu of other types of artificial lift when the well stops flowing (if the GLR is high enough) or earlier in an effort to lighten the flowing gradient and increase draw-down. In most cases where plunger lift is applicable it will produce a well at a rate equal to or greater than that obtained by pumping, because a high GLR, while necessary for plunger lift, reduces pump efficiency due to gas interference.

Once installed and operating, plunger lift can be expected to produce a well to depletion. As reservoir pressure (and thus maximum available casing pressure) declines, so do the producing rate and the need for a high casing pressure. There are a number of plunger lift wells operating with 70-100 psi casing pressure.

There are no absolute maximum producing rates for plunger lift as there are none for flowing wells. The limiting producing rate in both cases is as much dependent upon the inflow performance of the well as it is upon its outflow performance. Thus plunger lift should not be automatically ruled out at high producing rates. If high rates are required, the larger diameter plungers should be considered.

Plungers can also be used for paraffin removal and have been used in attempts to decrease GOR. A plunger does make a most efficient and economical paraffin scraper and several have been installed for this purpose alone. The attempts at GOR control are often unsuccessful. When the GOR does decrease, it is not due to decreased gas production, but rather increased oil production without an associated change in gas production.

The economy of plunger lift is one of the most appealing factors. The capital and operating costs of other alternatives almost always exceed those of plunger lift. The total cost of installing plunger lift is $1500 to $3000.

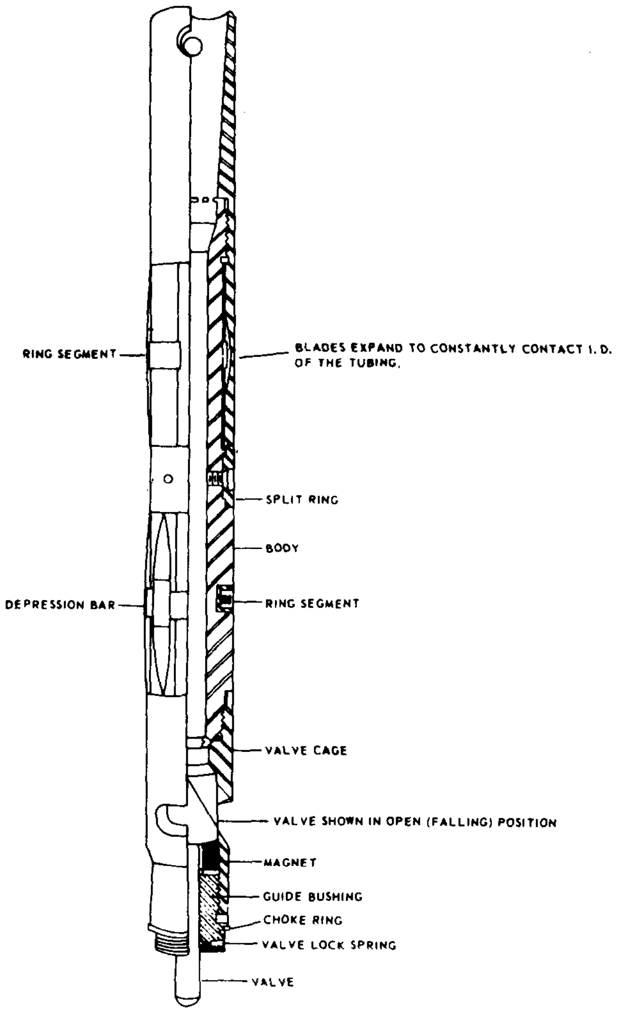
DISCUSSION

A plunger is a means of providing a solid and sealing interface between the lift gas and liquid load to be lifted. As such it uses the available gas energy more efficiently.

Plunger Types

Several types of plungers are available, including wobble washer plungers, turbulent seal plungers, and expanding blade plungers with or without an integral valve rod. Most plunger types exhibit one or more of the following desirable properties: (1) fast rate of fall through gas and liquid, (2) good efficiency (i.e., good sealing between plunger and tubing), (3) good repeatability of valve operation, (4) high degree of resistance to shock and wear, and (5) resistance to sticking in tubing. The expanding blade plunger without an integral valve rod (the valve opening rod is instead part of the bumper housing; see Figs. 1 and 3) exhibits the best overall quality; however, it may be slightly more likely to stick where there is sand or debris. If sticking of the expanding blade plunger is known to be a problem or if high efficiency is not required (gas wells and very high GLR oil wells), other types of plungers may be considered.

A plunger may be used in three general systems: (1) conventional plunger lift (no packer), (2) plunger lift with packer, and (3) intermittent gas lift with a plunger.

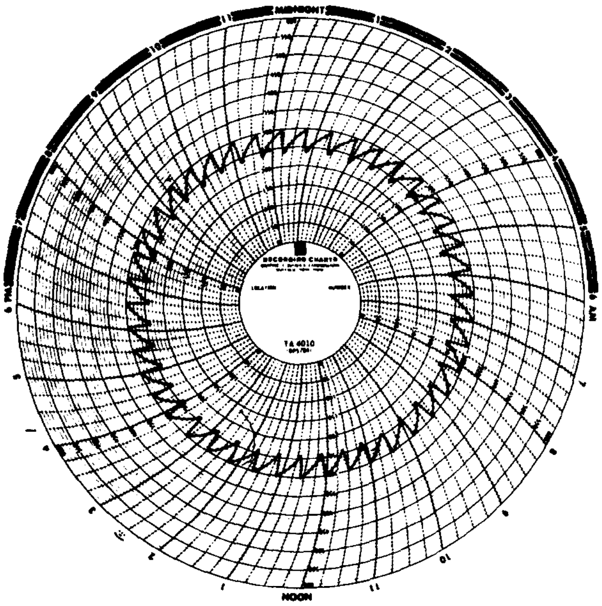


EXPANDING BLADE PLUNGER
FIGURE 1

Conventional Plunger Lift

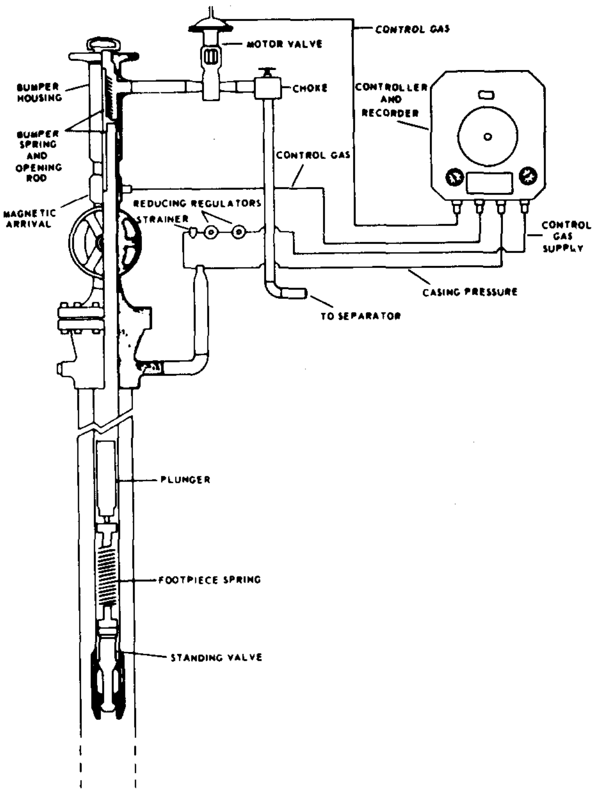
There are two means of controlling a conventional plunger lift installation. They are generally referred to as pressure control and time control.

Figure 2 shows a recording of casing pressure as the plunger cycles. The equipment used in a conventional pressure controlled plunger lift system with an expanding blade plunger is shown in Fig. 3. The operation of the system proceeds as follows: (1) The motor valve on the flowline is closed and the plunger is sitting on bottom. Gas pressure is building up in both the tubing and tubing-casing annulus. (2) When the casing pressure builds to a preset level, the controller opens the motor valve on the flowline. As the high pressure in the tubing bleeds off to the separator, a pressure differential develops across the plunger and it begins to rise. Gas accumulated in the annulus continues to expand (and decrease in pressure) into the tubing behind the rising plunger until it is forced to the surface. Note that while the plunger is rising there is no need for gas inflow from the formation. Gas already accumulated is doing the necessary work by expanding. (3) When the plunger arrives at the surface, it trips a trigger causing the motor valve on the flowline to close. Also, the valve opening rod in the bumper housing opens the valve in the lower end of the plunger allowing it to fall to the footpiece spring more quickly. (4) When the plunger strikes the footpiece, the plunger valve is closed and the plunger is ready to lift another load of liquid as soon as the casing pressure again builds to the preset level.



TYPICAL CASING PRESSURE CHART
FROM A PRESSURE CONTROLLED
PLUNGER LIFT INSTALLATION
FIGURE 2

The difference with time controlled operation is that the motor valve is both opened and closed at preset times instead of being opened at a preset casing pressure and closed upon plunger arrival at the surface.



PRESSURE CONTROLLED PLUNGER
INSTALLATION
FIGURE 3

Pressure control is designed to maximize plunger cycles per day, maximize liquid production and minimize gas production. It is, therefore, best suited for (1) oil wells which do not have excess gas available for plunger lift operation and (2) oil wells with high productivity indices even if they have excess gas available. In cases where there is excess gas, it should be bled off continuously from the casing.

Time control should generally be used on gas wells and oil wells with very high GLR's. Pressure control (designed to minimize gas production) of such wells results in unnecessarily long shut-in times and thus prevents maximum gas production.

Plunger Lift with Packer

This arrangement has very limited use. Generally it can be used only on gas wells with higher producing rates than are necessary with conventional plunger lift. Because of the packer, there is no annular supply of gas to expand and force the plunger upward. Instead, the required gas must come directly from the formation as the plunger is rising. Time control is the only means of control.

Intermittent Gas Lift with a Plunger

As mentioned earlier, a plunger uses lift gas more efficiently. In intermittent gas lift, high differential pressures are used so that the slug will reach high velocities and reduce liquid fallback. If a plunger is added, lower rising velocities (fallback is not a problem with plungers; the only fluid escaping by a plunger in either direction is gas slippage upward past the plunger) and lower differential pressures may be used. This means that larger slugs may be lifted with current system pressures.

Gas usage can be reduced or more slugs can be lifted with the same gas volumes if a plunger is added. In conventional plunger lift, gas consumption per cycle averages 1.15 times the gas contained within the tubing at a surface pressure equal to maximum casing pressure buildup. How closely the 1.15 value can be approached probably depends most upon the control system devised.

Intermittent gas lift becomes least effective at low formation pressures. Smaller slugs must be lifted to accomplish reasonable drawdown; however, to prevent excessive fallback a large slug is required. This paradox can be remedied either by installing conventional plunger lift (if the GLR is inadequate, the high pressure gas system can be used to supplement formation gas) or a plunger can be added to the gas lift system (no valves except the bottommost can be retrievable). Both are alternatives to the more complicated chamber lift. Use of plungers should reduce operating costs and capital outlay for compressor capacity.

A special type of intermittent gas lift is the subsurface liquid diverter (liquid is separated from gas; formation gas provides required casing pressure to operate gas lift valve and lift liquid up the tubing). It and plunger lift are both used to remove liquid accumulations from gas wells and high GLR oil wells. It apppears to have no advantages over plunger lift and has several disadvantages. Some of those disadvantages are: (1) liquid fallback, and thus the need for greater pressure differentials, does not allow as much drawdown; (2) regulating device (gas lift valve) is downhole rather than at the surface (pressure or time controller) as with plunger lift; (3) drawdown can be maximized only by repeatedly pulling the gas lift valve rather than by adjusting plunger lift surface controls; (4) reductions in casing pressure, such as installing a compressor, require that the valve pressures be lowered and sometimes that the subsurface liquid diverter be completely removed.

PREDICTING PERFORMANCE OF PRESSURE CONTROLLED PLUNGER LIFT

Limitations

Pressure control, and thus this technique, is generally applied only to oil wells. Its use assumes the use of the expanding blade plunger (Fig. 1) with its superior efficiency and falling rate. This is not a serious limitation since detailed prediction of plunger lift performance is not generally necessary under the conditions that other types of plungers are considered, i.e., gas wells and very high GLR oil wells.

This technique makes use of plunger lift performance charts presented in the paper by Foss and Gaul.[2] One of their charts is included (Fig. 4) to do the example problem; however, the others were not. To apply this technique to wells different from the example well, one must obtain a copy of the Foss and Gaul paper.[2]

General

For any particular well there is an absolute minimum GLR which is required for plunger lift operation. This minimum GLR is essentially dependent only upon the tubing size and the flowline pressure. If the GLR of the well in question is in excess of the minimum GLR required, then one can expect plunger lift to operate.

There is an optimum GLR which by necessity is greater than the minimum GLR required. The optimum GLR will produce the well at the maximum possible rate for that plunger lift installation; and either a higher or a lower GLR will result in a lower production rate from the well. At the optimum GLR the gas pressure that has accumulated in the annulus during one cycle of the plunger is just capable of lifting the liquid load that is present when the plunger reaches bottom. As a result, at optimum GLR the plunger operates at maximum cycle frequency since the plunger starts back up the tubing as soon as it reaches bottom and spends essentially no time sitting on bottom. The optimum GLR is a function of both the mechanical plunger lift equipment and the IPR of the well.

When the actual GLR is greater than the optimum GLR, a situation occurs in which gas is collecting in the annulus at such a high rate that when the plunger has completed a cycle and is back on bottom the gas pressure that has accumulated during this period of time is capable of lifting a larger liquid load than has accumulated during that same time period. Since the casing pressure is higher than necessary, the drawdown and production are less than at optimum GLR. In this case, gas should be produced from the annulus also.

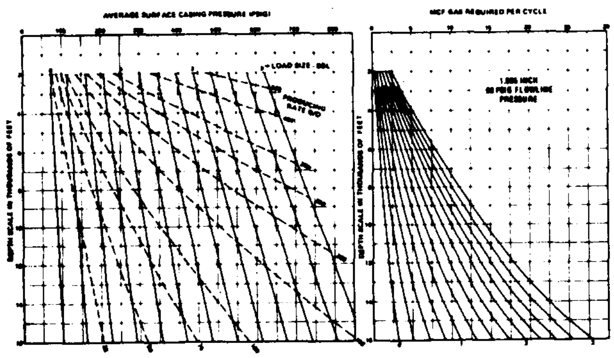
When the GLR is below the optimum GLR, production is again decreased. When the GLR is less than optimum, the plunger falls to bottom and must sit on bottom until enough gas pressure accumulates to lift the liquid load. However, while the plunger is sitting on bottom, the liquid load is not of constant size but is also increasing. The liquid load and the back pressure on the formation, due to the longer column of liquid, are larger than they would have been if the load were lifted as soon as the plunger hit bottom. Thus the drawdown and production are both decreased. In some cases it may prove economical to inject gas into the annulus to create an effective GLR which is equal to the optimum GLR.

The producing tendency of the plunger lift is directly opposite to that of the well. The plunger lift requires an increase of casing pressure for increased production whereas the well itself requires a decrease in casing pressure for increased production. The net result is always a compromise (even though the resulting rate is a compromise, it usually compares favorably with other artificial lift methods as stated earlier). The compromise which yields the greatest production (whatever the GLR) is always found when cycling the plunger at the maximum frequency possible for that GLR without killing the well. Therefore, production can be increased if the plunger cycle frequency can be increased. For a well with a GLR less than optimum, the plunger must necessarily sit on bottom for awhile. Thus its maximum cycle frequency will be less than for a well with optimum GLR.

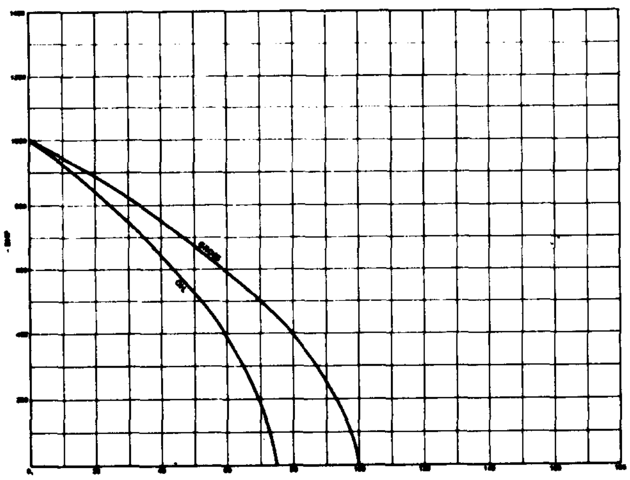
Example Well Data

Casing size: 5-1/2-in.
Tubing size: 2-in.
IPR: See Fig. 5
Depth: 6000 ft.
Flowline pressure: 60 psi

Two cases of this general problem will be analyzed. In one case the GLR will be 3000 and 7000 in the other.



APPROXIMATE CASING PRESSURE AND GAS REQUIREMENTS
FOR 1.995" PLUNGER LIFT
FIGURE 4



B/D
IPR OF EXAMPLE WELL
FIGURE 5

Determining the Minimum GLR

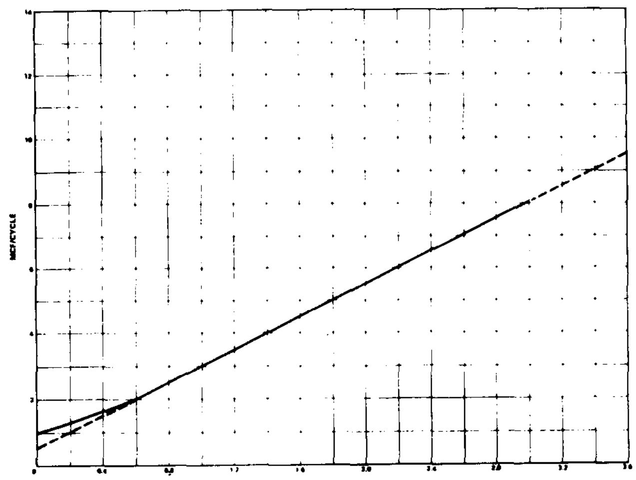
A well that has less than the minimum GLR required for a particular plunger lift installation cannot be expected to produce any liquid. When there is sufficient GLR (greater than minimum GLR) further analysis is required to predict how much liquid the well will produce with plunger lift.

To determine the minimum GLR required for plunger lift operation, refer to the set of curves on the right side of Fig. 4. Note that Fig. 4 is for 2-in. tubing and a 60 psi flowline pressure. Reading across at the 6000 ft depth, one can find the amount of gas required per cycle to lift a given amount of liquid per cycle.

Load Size bbl/cycle	Gas Required Mcf/cycle
0.00	0.9
0.25	1.4
0.50	1.9
0.75	2.4
1.00	3.0
1.50	4.3
2.00	5.5
2.50	6.8
3.00	8.1

This data is plotted in Fig. 6. The minimum GLR is equal to the slope of the straight line portion of this curve. Using the extrapolated values:

$$GLR_{min} = \frac{9.5 - 0.5\ (\text{Mcf/cycle})}{3.6 - 0\quad (\text{bbl/cycle})} = 2500 \text{ft}^3/\text{bbl}$$



LOAD SIZE—BBL/CYCLE
MINIMUM GAS REQUIREMENT
FIGURE 6

For comparison the minimum gas requirement and the available gas for three different GLR conditions are plotted in Fig. 7. These GLR conditions are (1) minimum GLR, (2) sufficient GLR, and (3) divergent GLR.

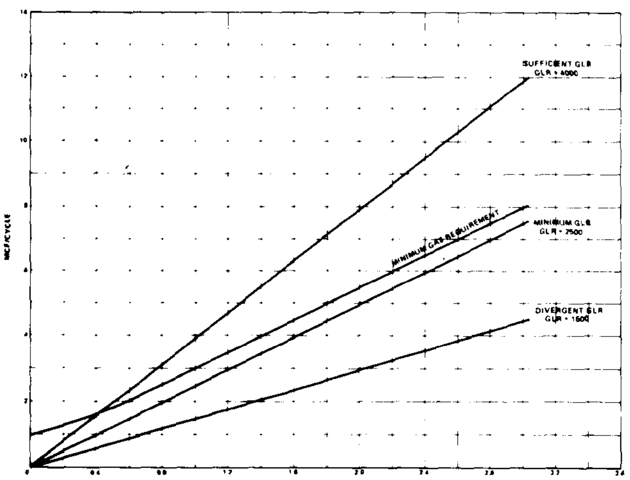
1. Minimum GLR—In this case the gas that enters the wellbore with any liquid load is just capable of lifting the liquid (no additional weight) to the surface. Thus plunger lift operation is impossible because all of the gas pressure available is needed to lift the liquid and there is no gas remaining to lift the plunger. The case of minimum GLR will give a line that

is parallel to the curve of minimum gas requirement. The minimum GLR decreases as the flowline pressure decreases and as the tubing size increases.

2. Sufficient GLR—Any GLR in excess of minimum GLR. In this case the GLR is high enough that the available gas is capable of lifting a total weight to the surface that is in excess of the weight of the liquid associated with that gas. The excess lifting capacity of the gas is used to lift the plunger.

In this case where GLR = 4000, the plunger and liquid can be brought to the surface when a load of 0.41 barrel (where the 4000 GLR line intersects the minimum gas requirement line) or larger has built up. At this point the available gas is capable of lifting the liquid and plunger weight. With a sufficient GLR plunger lift will operate but further analysis is required to predict production rates.

3. Divergent GLR—Any GLR less than the minimum GLR. In this case the gas available is not capable of lifting its associated liquid, much less the additional plunger weight. As liquid flows into the wellbore the difference between the gas required and the gas available to lift the load continually increases. Thus plunger lift operation is not possible.



LOAD SIZE—BBL/CYCLE
AVAILABLE GAS COMPARED TO REQUIRED GAS
FIGURE 7

Determining Optimum Operation

Determining the optimum conditions serves two purposes:

1. Whether the actual GLR of the well is greater or less than the optimum GLR dictates the type of analysis used in predicting production with that GLR.

2. Determining the production possible with an optimum GLR proves useful in considering the economics of injecting or removing gas from the annulus to create an effective GLR equal to the optimum GLR.

With an optimum GLR the plunger operates at maximum cycle frequency since the plunger starts back up the tubing as soon as it reaches bottom and spends essentially no time sitting on bottom. Referring to the left set of curves on Fig. 4 one finds a group of curves composed of dashed lines. These curves plot the production that is possible when operating at maximum cycle frequency versus the average casing pressure required at the surface to lift this rate of production. These curves will be used to determine the conditions necessary for optimum production.

Reading across at the 6000-ft depth the following data will be found. It is assumed that the annulus contains no liquid, only gas. Thus producing bottomhole pressure can be calculated by accounting for the gas gradient. In this case it was assumed that bottomhole pressure is 1.16 times the surface casing pressure.

BPD	AVERAGE SURFACE CASING PRESSURE	CALCULATED AVERAGE PRODUCING BOTTOMHOLE PRESSURE
25	110	128
50	146	169
75	184	214
100	222	257
150	307	356

Superimpose the data of BPD and bottomhole pressure (BHP) on an IPR curve as in Fig. 8. From this figure:

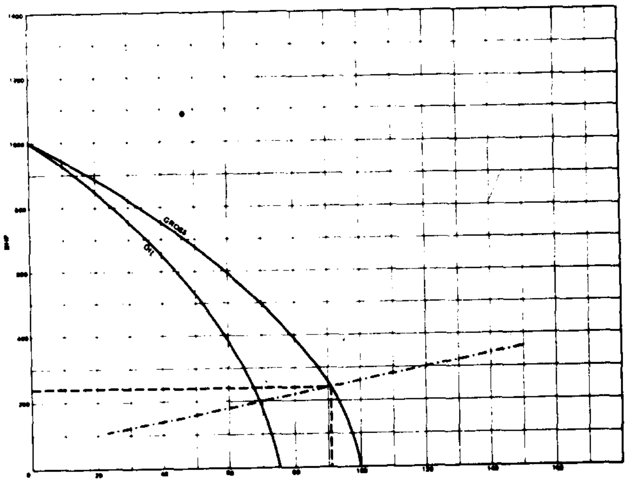
Producing BHP = 240 psi
Oil Production = 68 BPD
Gross Production = 91 BPD

The expected average surface casing pressure would be 207 psi (240/1.16=207).

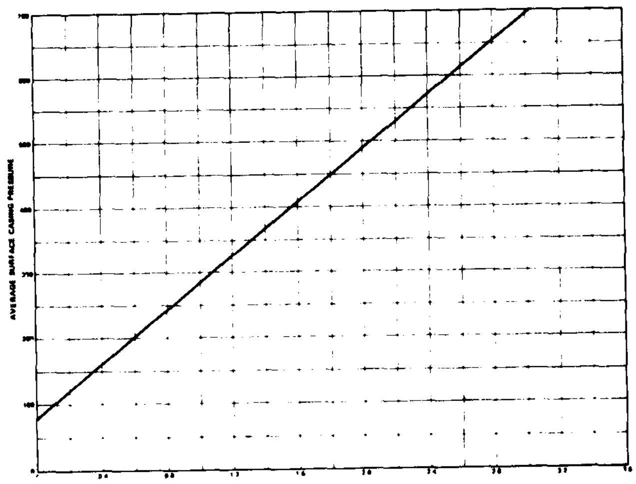
Referring to the left set of curves in Fig. 4 one will find a group of curves composed of solid lines. These curves give the casing pressure required to lift a certain load size. Reading across at the 6000-ft depth the following data was obtained:

Load Size (Bbl)	Average Surface Casing Pressure
0	80
1	285
2	490
3	695

This data when plotted results in a line as shown in Fig. 9. It was found previously that the average surface casing pressure was 207 psi. From Fig. 9 one can determine that the load size for each cycle of the plunger will be 0.62 barrel. Since gross production is known to be 91 BPD, the cycle frequency will be 147 cycles/day (91/0.62=147).



B/D
PRODUCTION AT OPTIMUM GLR
FIGURE 8

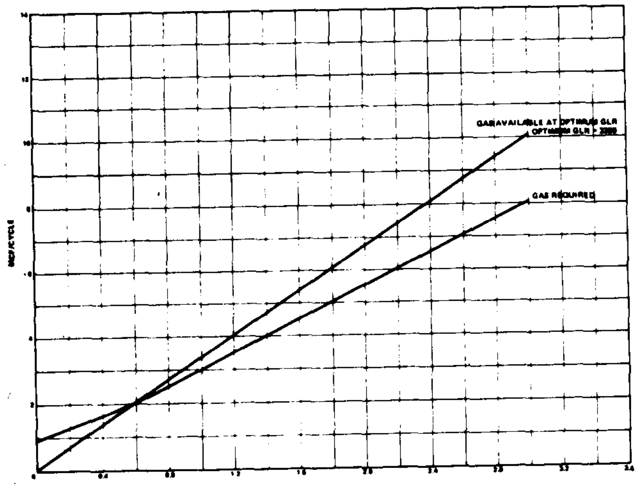


LOAD SIZE—BBL/CYCLE
PRESSURE REQUIREMENTS
FIGURE 9

From Fig. 10 one finds that 2.1 Mcf/cycle of gas is required to lift the 0.62 barrel load. Thus the optimum GLR is 3380 ft^3/bbl.

$$GLR_{opt} = \frac{2.1 \text{ Mcf/cycle}}{0.62 \text{ bbl/cycle}} = 3380 \text{ ft}^3/\text{bbl}$$

By comparing the required gas and the gas available at the optimum GLR as in Fig. 10 the load size is again found to be 0.62 barrel (where the two lines intersect) and serves as a check on the previously determined value.



LOAD SIZE—BBL/CYCLE
FIGURE 10

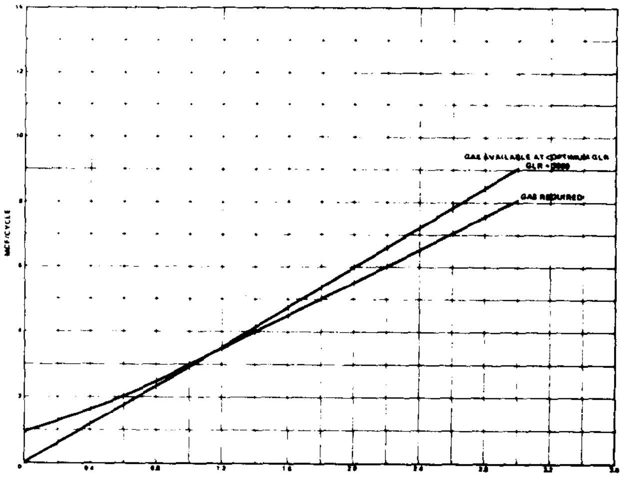
Analyzing A Well With Less Than Optimum GLR

When the plunger reaches bottom, the casing gas pressure is not adequate to lift the liquid load that is present at that time. Therefore, the plunger must sit on bottom until the pressure is adequate. However, while the pressure is increasing, the inflow from the well is causing the liquid load to increase simultaneously. Using the assumed GLR of 3000 and the gas requirements of Fig. 6, Fig. 11 can be made. Figure 11 shows that the load may be lifted to the surface when it has increased to 1.1 barrels in size. At this point gas available is equal to the gas required. By referring to Fig. 9 the gas pressure at this time will be 305 psi. Therefore, the BHP while producing with a 3000 GLR will be 354 psi (305 x 1.16=354).

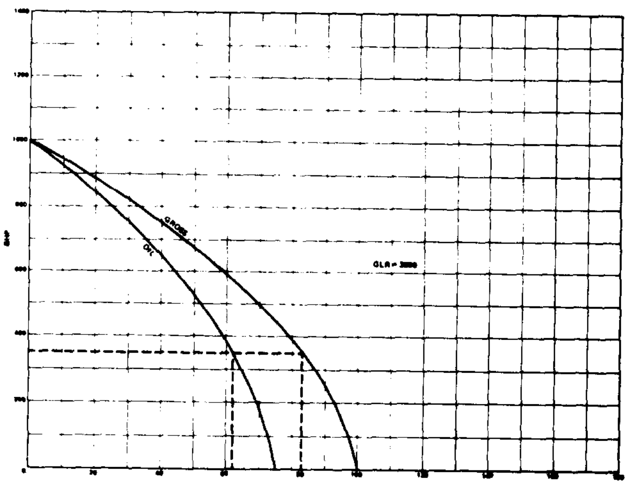
At 354 psi this well will produce 62 BOPD and 83 BPD gross as shown on the IPR curve of Fig. 12. Therefore, the plunger will cycle 75.5

times per day:

83 BPD/(1.1 bbl/cycle) = 75.5 cycles/day



LOAD SIZE—BBL/CYCLE
FIGURE 11



B/D
PRODUCTION AT LESS THAN OPTIMUM GLR
FIGURE 12

Analyzing A Well With Greater Than Optimum GLR

Previously with a GLR less than optimum the procedure was to determine the load size and then the annulus pressure necessary to lift the load. However, with a GLR greater than optimum the gas pressure is in excess of that necessary to lift the loads and the problem becomes one of determining to what extent the excess pressure in the annulus is decreasing production. If the lost production is significant, one would want to produce the excess gas from the annulus.

A concept to be used for this analysis is pseudo load size. It is a tool used to analyze wells with greater than optimum GLR. From an assumed gas production per cycle, one can determine the size load this gas can lift from Fig. 6. By using this load size with Fig. 9 the casing pressure that would be present can be determined. Since this load size has no physical significance and is only an intermediate step to get from a gas rate to a casing pressure, it is termed a pseudo load size.

For this analysis use the same cycle frequency as was obtained with an optimum GLR. In this case 147 cycles/day.

Figure 13 compares required and available gas for the 7000 GLR and the following data is that compiled for the graphical solution of Fig. 14:

Col. (1) Assumed gas rates starting at the lowest rate (1.25 Mcf/cycle) that can produce liquid. Refer to Fig. 13.
Col. (2) Determined From Fig. 6.
Col. (3) Determined from Fig. 9.
Col. (4) BHP is equal to 1.16 times the average surface casing pressure to correct to a depth of 6000 ft.
Col. (5) Actual production rates from the assumed gas rates. For example, at 2 Mcf/cycle:

(1) Mcf/cycle	(2) Pseudo Load Size bbl/cycle	(3) Average Surface Casing Pressure	(4) BHP	(5) BPD
1.25	0.18	117	136	26.2
2.0	0.57	195	226	42
3.0	0.98	280	326	63
4.0	1.38	360	418	84
5.0	1.78	445	516	104
6.0	2.19	530	615	126

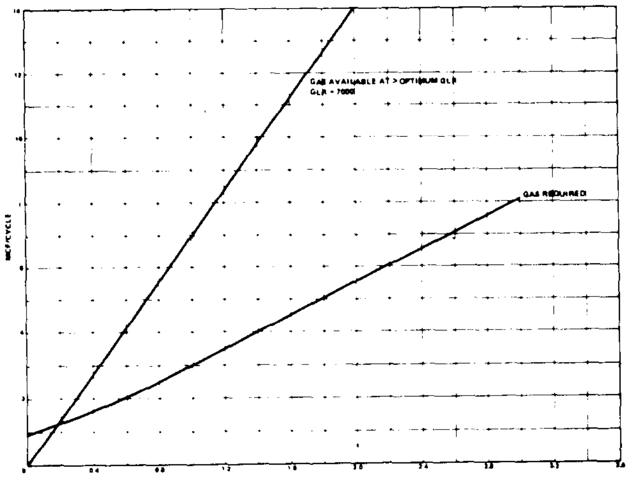
$$\frac{(2\ \text{Mcf/cycle})\ (147\ \text{cycles/day})}{7000\ \text{ft}^3/\text{bbl}} = 42\ \text{BPD}$$

Note that this will give an actual load size which is not equal to the pseudo load size:

$$\frac{42\ \text{BPD}}{147\ \text{cycles/day}} = 0.286\ \text{bbl/cycle} \neq 0.57\ \text{bbl/cycle}$$

By superimposing the data of Columns (4) and (5) on an IPR curve such as in Fig. 14, the graphical solution predicts a BHP of 400 psi and production of 59 BOPD and 79 BPD gross. The average surface casing pressure will be 345 psi (400/1.16 = 345) and the load size will be 0.54 bbl/cycle:

(79 BPD)/(147 cycles/day) = 0.54 bbl/cycle



LOAD SIZE—BBL/CYCLE
FIGURE 13

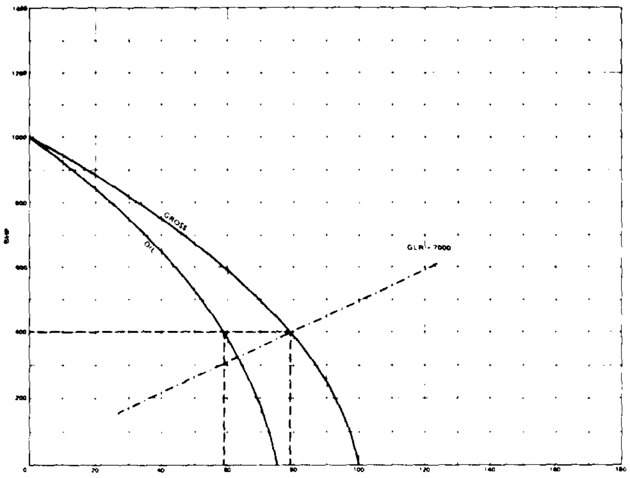
Comparison of Results

GLR	Minimum GLR = 2525	Less Than Optimum GLR = 3000	Optimum GLR = 3380	Greater Than Optimum GLR = 7000
BPD Oil	0	62	68	59
BPD Gross	0	83	91	79
Producing Bottomhole Pressure	Static	354	240	400
Average Surface Casing Pressure	—	305	207	345
Load Size (bbl/cycle)	—	1.1	0.62	0.54
Plunger Cycle Frequency (cycles/day)	—	75.5	147	147

OTHER PREDICTIONS

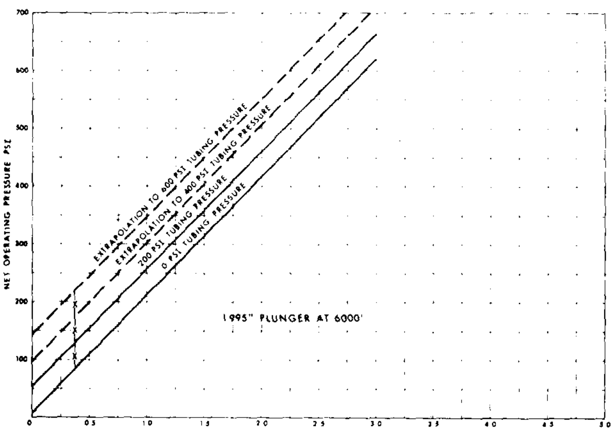
Time Controlled Plunger Lift

Plunger lift of this type is usually applied to gas wells and very high GLR oil wells. Gas wells often have flowing tubing pressures higher than those (200 psi maximum) presented by Foss and Gaul.[2] In order to analyze those wells it is necessary to generate curves for the higher pressures from the data available at lower pressures. This was done in Fig. 15. The net operating pressure referred to in Fig. 15 is the amount of casing pressure over and above the minimum



PRODUCTION AT GREATER THAN
OPTIMUM GLR
FIGURE 14

flowline pressure, or simply the casing pressure if one chooses to unload to atmosphere. The procedure is to enter the two appropriate graphs (like Fig. 4, except 0 psi and 200 psi) and plot net operating pressure (average casing pressure less 0 or 200 psi) versus load size. Those two lines will permit an extrapolation to other tubing pressures.



BBL/CYCLE
GENERATING DATA FOR TBG. PRESS. 200 PSI
FIGURE 15

The only method of estimating production increases due to time controlled plunger lift is to assume that the new flowing gradient with plunger lift is that of dry gas and apply that information to the IPR curve.

Note that a gas well producing very little liquid can load up and quit flowing. Once the gas rate is inadequate to carry liquid out of a well, it will begin to load up no matter how little liquid there is. At low liquid to gas ratios it will simply take longer to completely load up.

Plunger Lift With Packer

Precautions must be taken to prevent attempted application of this method where it cannot work. As mentioned earlier, all gas required to lift the plunger must come directly from the formation (not expansion of accumulated gas).

One must first estimate what size load is to be lifted with the plunger. Then go to an appropriate graph (like Fig. 4 or Fig. 15) to estimate the casing pressure (if there were an annulus) required to lift that load. Estimate the flowing rate with a dry gas gradient (due to the plunger). Using the estimated rate and pressure and the tubing size in the well, calculate the gas velocity up the tubing. If that gas velocity is not greater than 750 ft/min (minimum plunger rising velocity) then plunger lift should not be used.

CONCLUSION

Plunger lift has not been used in significant quantities nor to its full potential because most operators lack adequate understanding of plunger lift principles and due to conjecture that plunger lift is not reliable and rugged. The few plunger lift failures are probably due to (1) attempts to install it in wells where it was not suited, (2) poor quality plunger lift hardware, and (3) the inadequacies of personnel installing and servicing plunger lift. A nearly perfect success ratio can be expected if a rigorous analysis is performed on each well and the very best in hardware and personnel is used.

Plungers can be used to remove liquids from oil and gas wells, to remove paraffin from tubing, and to improve performance of intermittent gas lift. In each application it should offer both operating and economic advantages over the alternatives.

REFERENCES

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