WILL PLUNGER LIFT WORK IN MY WELL?

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ABSTRACT

The purpose of this paper is to answer the ten most asked questions about plunger lift.

1. Do I Have Enough Pressure?
2. Do I Have Enough Gas Volume?
3. Will It Run Under A Packer?
4. Is My Sales Line Pressure Too High?
5. What Is My Operating And Maintenance Cost?
6. How Long Will It Be Effective?
7. Will It Work With Gas Lift?
8. Will It Work In Paraffin?
9. How Much Improvement Can Be Expected?
10. Will I Eventually Need A Pumping Unit?

From these ten questions we can identify the areas of interest as Identifying a Candidate, Operating Cost and Economics and will answer the questions in those areas.

INTRODUCTION

The increasing interest in plunger systems is a combination of changing economic climates and improvement of plunger equipment. Development of new equipment and techniques have broadened the spectrum of wells that can be helped by proper plunger application.

Judicious production engineering has prompted a renewed interest in marginal wells and economical alternatives for producing all wells.

Invariably, supervisors and engineers that are unfamiliar with plunger usage are faced with one or more basic questions. This paper attempts to address these very logical concerns.

QUESTIONS

Do I Have Enough Pressure To Run A Plunger?

This is the first and most often asked question by people unfamilar with the operational needs of plungers. The question is reasonable because they don't realize the effect pressure plays in the operation. It is also one of the hardest questions to answer.

If plungers all had a perfect seal and operated in a smooth continuous cylinder, then the only pressure needed to move the plunger could be calculated by dividing the weight of the tool by the cross sectional area of the tubing. Additional force would result in movement. API tubing does not come with a smooth continuous bore. The variation in the internal cross sectional area of 2-3/8 in. EUE tubing is from drift (2.8383 sq.in.) to nominal (3.1259 sq.in.). This difference in area (.2876 sq.in.) is almost equal to a hole with a diameter of 5/8 in. In 2-7/8 in. EUE the difference is almost a 23/32 in. hole. If we consider the normal bore of a 2 in. christmas tree 2.0625 in. ID (3.3410 sq.in.) then the variation is greater than a 3/4 in. hole.

These figures may seem tangential to the question but they point out the importance of the seal section of the plunger. A solid bar stock type plunger has a maximum OD smaller than drift dimension of the tubing. It automatically has a bypass area equivalent to at least a 5/8 in. hole. Therefore, it cannot be as effective as a tool with an expanding element that restricts this 5/8 in. bypass. The differential pressure needed to move tools of the same weight would vary with the type of seal. Additional bypass, as suggested by proponents of capillary plungers is not necessary. If we stop at this point then we could say we need a differential pressure of 5 to 7 psi to move the average plunger. However, the purpose of the plunger is to help move liquid up the tubing.

How large a slug can we lift? To answer this question many variables come into play, but mainly it is the capability of the well and its' facilities to furnish a constant differential force across the plunger and the slug during its upward travel to the surface. Notice the use of the term "differential force"; which should be interpreted to mean "net pressure". Net pressure can be identified as the casing pressure minus the maximum sales line pressure during a cycle. This net pressure converted to a hydrostatic head is often used as the theoretical starting point for determining the slug size capacity of the plunger. Other factors to be considered are the friction created by the length of the slug; the additional force necessary to accelerate the slug; and the amount of liquid the well produces behind the plunger during the upward cycle of the tool.

A conservative slug size in the tubing would be 50 percent of the net pressure at the start of a cycle. This slug could be larger depending on the capability of the well to produce, and the capacity of the surface facilities to accept the high rate of production.

It is important to note that we have not limited the size of the slug. In cases of low pressure but high productivity these slugs can be fractions of a barrel. There are many installations around the world where plungers are operating at less than 100 psi maximum casing pressure and producing 5 to 8 barrels of liquid a day in wells as deep as 6000 ft. Plungers are very applicable in old gas fields where small amounts of liquid will cause loading and reduce production. Conversely there are many high pressure wells considered for plungers, but because of high line pressure the net pressure is not great enough to effectively operate an installation.

Do I Have Enough Gas Volume?

The most important question pertaining to a plunger installation concerns gas volume. Gas expansion is the motivating force for any plunger installation. In oil or gas production it is this expanding force that creates the necessary velocity to carry the liquid to the surface. When wells start to die, in most cases it can be directly related to the manner in which the gas is produced. This may be caused by such restrictions as small chokes, high line pressure, or a change in the gas liquid ratio (water increase). The plunger's role in producing a well is to reduce the need for such high velocities (critical velocity) by improving the efficiency of the gas flow needed to produce the liquid.

A rule of thumb that has been used for years to estimate the volume of gas necessary for a successful operation is, "400 cu.ft. per barrel per 1000 ft. of lift". This "rule of thumb" had its beginning based on the Hp in a compressed volume of 400 cu.ft. of gas and expanding this gas under the hydrostatic head of a barrel of liquid. However, no consideration was given to the back pressure above the head of liquid. If this back pressure was excessive, then more gas volume than 400 cu.ft. per barrel would be necessary for 1000 ft. of lift. When using this rule, always consider it the minimum gas requirement.

For many installations this rule still applies. Most oil wells that require help in the form of plunger lift are produced from intermediate depths and into low pressure systems (100 psi or less) so the rule would apply. When the well is deeper or produced into a higher pressure system, then additional volume will be needed. If the gas liquid ratio is higher, it is even more advantageous.

A paper written by D. L. Foss and R. B. Gaul based on their experiences with plunger lift in the Ventura Avenue Field offers a more technical approach to necessary gas liquid ratios[1]. The curves they were able to derive point out the effect of back pressure but is limited to maximums of 200 psi.

In all cases the gas volume, under pressure, must be available for use throughout the cycle and should not be impeded by small orifices where communication between tubing and casing is accomplished by wireline perforation.

Will A Plunger Run Under A Packer?

All prudent operators would like to be able to install any piece of equipment with a minimum of expense. If he has a candidate for plunger lift, but the well has a packer, he may be reluctant to pull the packer for the installation of a plunger. The reasons may be good, but he should consider his options.

Pumping wells do better without a packer and so do plungers. Pumping wells producethe formation gas out of the casing to prevent gas lock of the pump. Plunger wells save this gas in the casing and use it to furnish the energy to lift the liquid and tool to the surface. Why not pull the well and set it up for a pumping unit for use at some later time if the plunger does not prove satisfactory? Since the plunger and its' related downhole equipment is wireline retrievable the operator would not have any additional rig time to install a pump other than a rod job.

This is not to say that plungers won't run in wells equipped with a packer. They will if the formation has the capacity to furnish lift energy at a rate high enough to sustain the necessary velocity of the slug to the surface. Few wells have formations with this capacity. They are most likely to be found in old fields where the loading problem is due to declining bottom hole pressure.

The advantage of an open installation (no packer) is the capability to store formation gas in the casing. It is this reserve energy that helps formations with lower productivity sustain high instantaneous rates necessary to surface the plunger and its' liquid. When the plunger completes its' cycle the well is shut in for the tool to return to the bottom for another load. At this time the reservoir continues to produce and repressure the casing. The shut in time may exceed the time required for the plunger to return to the bottom, but it should be long enough for the casing to regain its' initial pressure.

Another advantage of an open installation is that a well can be produced at a lower flowing bottom hole pressure. Subsequently the life of the installation is longer. In many cases this can mean producing the well to depletion.

Is My Sales Line Pressure Too High?

Temporary fluctuations in sales line pressure can be caused by new wells coming on the line at higher pressures or large volumes that tax existing flowline or compressor capacities.

Increased line pressure can be detrimental because it changes the relationship between the forces above and below the plunger. This requires a resultant increase in casing pressure or gas liquid ratio for the same produced liquid volumes.

For sustained higher line pressures it would be necessary to adjust the operating casing pressure or produce to a lower pressure system with tubing sales.

Surface facilities of wells on plunger lift are a critical part of a successful installation. They must be able to absorb high gas rates needed to accelerate the plunger without abnormal pressure build up. Once the liquid arrives at the surface the separator must dump the liquid without carry-over into the sales line.

A slug of liquid in 2-3/8 in. tubing traveling at a speed of 1000 ft. per minute is actually producing at a rate of 5760 BPD. Not many separators are designed for this high rate of production. If the slug is large the trim in the dump valve of the separator may have to be changed to prevent carry-over. Once the liquid has reached the surface it must flow through the control valve (intermitter) on the flowline. By sizing the trim in this valve the rate can be controlled and still be efficient. An optimum installation has as high a rate capacity as possible.

At the start of a cycle the tubing pressure will be at its' maximum and when the controller opens the initial surge on the gas system may outrun the gas sales meter. The differential pen can go off the chart and the producer loses gas sales. Other wells producing into the same gathering line can be affected (not always adversely). Gas measurement is difficult and probably the most detracting part of a plunger installation.

There are ways to overcome these objections. One should use as large an orifice plate in the meter as possible. Combine this with a faster rotation clock to spread the spikes on the chart for easier reading. If the pen is still spiking off the chart, a regulator can be installed in series with the controller to throttle the control valve and dissipate the initial surge of gas. There are also some new electronic metering devices that can be added to an existing meter to facilitate better measurement at abnormal differentials.

Plungers can also be used on a single well with a compressor. This type of installation is difficult to operate but it can be rewarding. That old phrase "a compressor sucking on a well never lifted a single barrel of liquid" is true. The well just produced against a lower surface pressure. The addition of a plunger increases the lift efficiency, but since the flow must be shut off or reduced for the plunger to return to the bottom, some method of gas rotation or speed control must be used on the compressor. The system must be custom designed for each well.

What Is My Operating And Maintenance Cost?

A typical plunger installation has a nominal operating cost, and it varies little with the depth of the well.

Mechanical costs would be primarily replacement or repair of the plunger itself. As the only dynamic portion of the system, it receives the majority of the wear. A conservative figure for most plungers under normal conditions would be $500 per year. This may vary slightly on deeper wells and more severe conditions.

After the installation and initial adjustment period, personnel time is a consideration. The system needs monitoring for small adjustments due to changing well producing characteristics or external conditions such as line pressure. A two pen recorder eliminates the necessity of full time surveillance. Normally these adjustments can be made on the normal "rounds" of the well operator.

If a mechanical controller is used it would be necessary to wind the clock weekly. The new electronic controllers do not require any winding, but do require a battery change every 8 - 12 months.

A good practice is a regular inspection of the plunger. Most plunger systems have an "automatic" catcher that can be set to catch the plunger on the next trip without the necessity of the well operator's presence.

The plunger should be inspected at least once a month, preferably every week or two. Excessive wear can be detected before it causes a problem. If the plunger is allowed to run with too much wear it will become less and less efficient. This may cause the well to load up and the tool may eventually fail. This inspection should take no more than 15 minutes per well.

Compared with other types of lift systems the plunger is inexpensive to purchase and operate.

A pump jack has not only a fuel cost, but engine maintenance, stuffing box maintenance, rod jobs and pump repair. Considerable personnel time and mechanical expense are involved. A comparison with pump fuel cost alone is not a true representation.

How Long Will It Be Effective?

A major factor in the effective life of the system is the hardware itself. Starting from the bottom up:

1. The stop and spring at the lower end of the plunger travel is not normally subject to much wear or deterioration. Discounting any severe conditions such as sand production or unusual corrosion, these items should not require any maintenance and should last almost indefinitely.

2. The plunger is basically the only major moving part and does require a certain amount of attention. Depending on the type of plunger and the material of which it is constructed, wear is a factor. Tool velocity and liquid slug size affect plunger longevity and, of course, oil provides more lubrication than does condensate or water. Excessive wear can occur when the tool is run at velocities above 1000 fpm. If this high velocity is caused by running the tool with very small loads and high differentials, it can be remedied by cycle adjustment. In some cases it is necessary to cycle the plunger faster because of well depth and response. Lea did a detailed study on the increased efficiency of faster plunger travel[2]. This combined with increased production may offset any additional wear. Periodic inspection of the plunger and repair or exchange when necessary usually insures continuous operation.

3. The surface equipment including the lubricator and catcher are practically maintenance free and should last for years.

4. The controller and motor valve may need occasional stem and seat replacement or clock repair. Electronic controllers require little or no maintenance.

The type of well and reservoir as well as its' depth and mechanical conditions dictate the duration of plunger effectiveness. Gas or oil reservoirs with the ability to sustain high gas to liquid volumes as pressures decline lend themselves to plunger operation.

Effectiveness can also be influenced by changing external conditions, such as fluctuating sales line pressures. These conditions can be compensated for as explained in a previous section.

New lightweight plungers allow operation with net pressures between casing and sales line lower than 100 psi in moderate depth (5000-6000 ft.) wells. Some shallow gas wells (2000-3000 ft.) vent liquids to atmosphere until plunger arrival and sell gas from the casing as low as 70 psi.

By applying these casing pressures to the IPR curve for your well it is possible to predict the duration of plunger effectiveness. In most cases it is very near depletion.

Tight, high pressure reservoirs that decline in pressure rapidly have a shorter duration of plunger usefulness but the system may still serve as a useful interim measure and may be moved inexpensively.

It should be remembered that a plunger system is 100 percent recoverable without the use of a rig, and is easily transferable to another well.

Will It Work With Gas Lift?

There is substantial evidence that virtually every intermittent gas lift well would benefit from utilizing a plunger.

Intermittent gas lift has several inherent problems that can be improved upon or eliminated by the use of a mechanical interface. A plunger placed above the operating valve between the lift gas and the liquid to be lifted affords dramatic increases in efficiency.

Inherent problems with intermittent gas lift:

1. Fall back: This is defined as the liquid that falls back down the tubing after the lift gas has broken through that portion of the liquid slug. The primary cause is the rising bubble of injected gas has a greater velocity in the center of the tubing string than at the perimeter. This coupled with the co-efficient of friction between the tubing wall and the slug causes liquids to be by-passed by the lifting energy. As pressure equalizes across this liquid it "falls back" down hole to be lifted in the next slug. This requires liquids to be lifted repeatedly before finally being produced with large amounts of gas being required per volume of liquid produced. This inefficiency also creates an unnecessarily heavy flowing gradient in the tubing causing higher flowing bottom hole pressures and reduced drawdown. This decreased drawdown results in less inflow from the formation.

2. Submergence: This is defined as the vertical column of fluid necessary for a beginning intermittent slug to assure an acceptable recovery of liquid at the surface. Fallback percentage increases with depth, so the deeper the well, the more submergence necessary for an acceptable liquid recovery per slug. This would eliminate

some deeper wells without enough bottom hole pressure to support the proper column of submergence.

Fill-in from the formation is relative to the pressure exerted by an increasing hydrostatic column. The higher the column must be, the longer the time period necessary. Fill-in is more rapid at the beginning so there is a distinct advantage in being able to work with smaller liquid slugs (Fig.1). Cycle frequencies may be increased and should result in some additional production.

Installation of a plunger eliminates or drastically reduces all of the above problems by acting as a mechanical interface between lift gas and produced liquids. It virtually sweeps the tubing of all liquids and deposits. There is no liquid slippage by the plunger downward because the pressure is always greater beneath the plunger than above. There may be a negligible amount of liquids left in collar recesses, but for all practical purposes the tubing is clean.

The resultant benefits are:

A. Increased gas lift efficiency

B. Decreased gas requirements

C. Increased formation drawdown and inflow

D. Reduced need for submergence allowing deeper, lower pressure wells to be lifted

Will It Work In Paraffin?

Paraffin is normally perceived to be large globs of a hard brown substance seen around well sites after cutting. In this stage it would appear to be a formidable problem in the wellbore.

Actually, paraffin is carried in solution as long as the temperature remains above a certain value. On the Gulf Coast for instance, that value is 100°F. While the surface flowing temperature remains above that temperature, paraffin is transferred into the flowline. Decreasing temperatures can be caused by decreased flow, gas breaking out of solution or gas lift gas. This initiates a film of paraffin forming at the top of the tubing string and in the tree. If there is no interruption, the paraffin begins to harden and the rougher surface is even more conducive to additional adherance. This process continues down hole until the temperature is reached at which paraffin stays in solution. As paraffin continues to form uphole it creates a choking effect which slows down flow and causes further reduction of temperatures. If allowed to continue, the well may plug completely off.

The mechanical wiping action of the plunger interrupts this formation by constantly removing the film of paraffin before it hardens.

The intermittent on-off action of the plunger also moves fluid up the hole at a faster rate than normal flow so there is less temperature drop and less time for deposition. Normally there is little or no flow of liquids after the plunger runs, so there is little chance to form new deposits.

A plunger that runs at least 3 - 4 times a day will control all but the most severe paraffin problem.

How Much Improvement Can Be Expected?

Statements made here are of necessity in general terms but experience has shown the following improvements should be realized when using a plunger system for:

1. Paraffin Control: The elimination of paraffin has several beneficial results. The daily production increase will be the difference between the well being produced clean or with reduction due to the choking effect of the paraffin.

Paraffin "cutting" costs should be eliminated. Down time due to complete blockage should also be prevented as well as the down time necessary to "cut" the paraffin. The production increase will be a function of severity of the problem.

2. Gas Well Unloading: Gas wells having producing rates that fall below a certain critical velocity exhibit a production decline curve with a deviation from the norm (Fig.2). This is evidence of liquid loading.

A gas well that is prevented from loading up will re-establish a normal decline (Fig.2). The increase in production will come primarily from the cumulative increase due to absence of loading (Fig.2). By producing liquids and gas with the lowest gradient and lowest flowing bottom hole pressures the well is allowed to produce to its' maximum capability.

3. Hi-Ratio Oil Wells: An oil well that is "heading" and attempting to lift liquids with formation gas is normally very inefficient. By installation of a plunger one is able to control and stabilize the on-off cycles and eliminate the inherent slippage and fall back. This enables the well to be operated efficiently at the lowest bottom hole pressure and assures maximum drawdown and production. The flowing bottom hole pressures can be predicted by reference to the works of Foss and Gaul in correlating depth, ratios and flowline pressures[1].

There is a relationship between flowing bottom hole pressures and well productivity. This may be used to predict performance.

4. Gas Lift Wells: The advantage of reducing or eliminating fallback will result in reduction of gas injection requirements of 30 - 70 percent. This varies with depth, injection pressures, wellhead pressures, tubing size and liquid composition. Subsequently, more wells may be lifted with the same system.

Production increase will result from reduced average flowing gradient and flowing bottom hole pressures. The ability of the well to feed in is the determining factor. This is also influenced by depth, injection pressures, tubing size and type of liquid. However, increases of 10 - 15 percent or even more are not uncommon.

Will I Eventually Need A Pumping Unit?

There is no definite answer here because of the many variables involved. The knowledge that new equipment and techniques allow plunger operation to much lower pressures and volumes offers new perspectives in decision-making.

In many cases plungers are able to produce to such low pressures that wells may have reached physical or economic depletion.

The economics here are based on your ability to predict the following:

1. Production decline
2. Reservoir capabilities
3. Future oil and gas prices
4. Future pump equipment prices
5. Future interest rates (for discounting)

CONCLUSION

These questions are the most common concerns of producers contemplating the use of plungers. It is the purpose of this paper to answer these questions with a combination of technical knowledge, empirical data and field experience. There will be individual wells that require closer scrutiny, and should be discussed with your manufacturer's representative.

In our industry today there is a certain amount of economic uncertainty. A plunger system, if applied and operated properly, can be an astute investment. Particularly if it is viewed in terms of return on that investment. Whether utilized as a permanent or an interim solution, maximum results are usually obtained with a minimum of expenditures.

REFERENCES

1. Foss, D. L., and Gaul, R. B., "Plunger Lift Performance Criteria with Operating Experience - Ventura Avenue Field", API Drilling and Production Practice, 1965.
2. Lea, James F., "Dynamic Analysis of Plunger Lift Operations", Journal of Petroleum Technology, Vol. 34, No. 11, pp 2617-2629, Nov. 1982.

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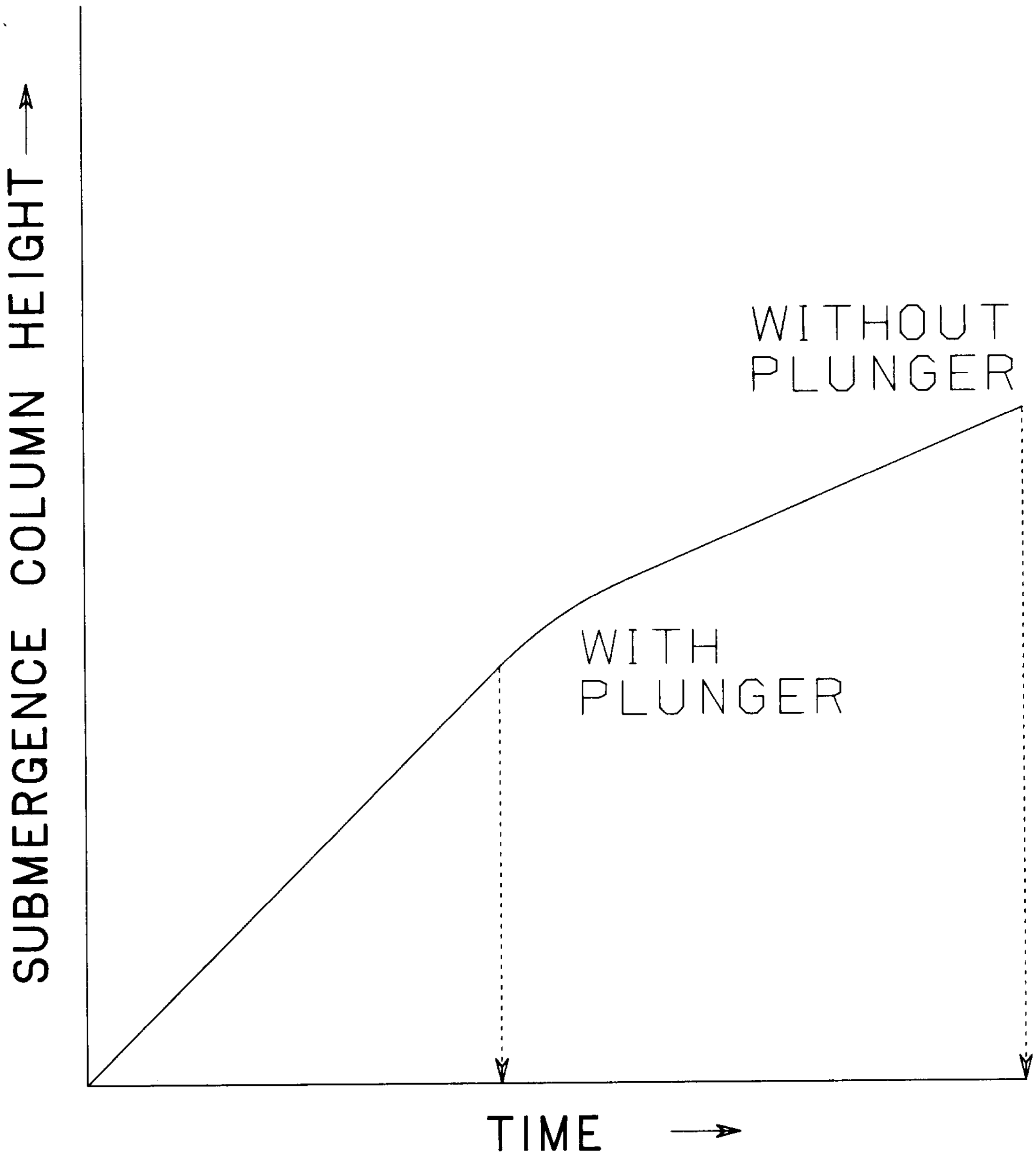
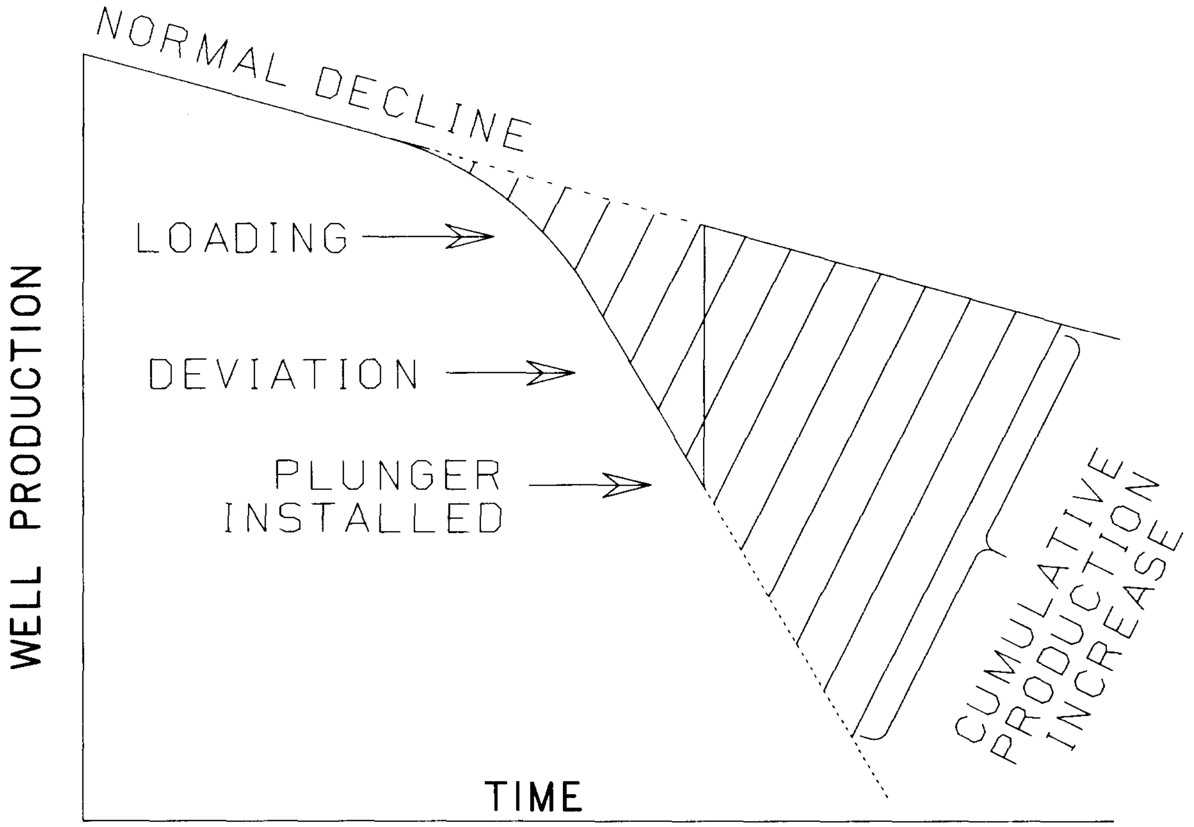


REQUIRED SUBMERGENCE IN A
LOW PRESS. INTERMITTENT
GAS LIFT WELL

FIGURE 1

TOP



TYPICAL GAS WELL PRODUCTION DECLINE CURVE

FIGURE 2