ARTIFICIAL LIFTING WITH PLUNGER LIFT SYSTEMS

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The method of artificial lift using the plunger lift system has been, until recently, the most overlooked and neglected of all the lift systems being utilized today. Why? For the most part, it has been misunderstood by operators, or in some cases operators have experienced failures due to antiquated systems, or misapplication on wells not suited to this form of lift.

What form of artificial lift could be more efficient or economical than one which allows the energy produced by the well to produce the well? Plunger lift does just that. Yes, the energy stored in the formation in the form of gas and pressure is used to produce the well's own liquids to surface by using a piston as an interface between the liquid slug and the drive gas. This is known as plunger lift.

In the past several years, advancements have been made in plunger lift equipment and technology. First, it is appropriate to review how a plunger system works, and what it does.

HOW PLUNGER LIFT WORKS

The plunger lift system is a method of artificial lift that utilizes energy from the formation in the form of gas and gas pressure stored in the casing to force a free piston (plunger) to travel up and down the tubing in a cyclic manner. With the well shut in, the plunger falls to the bottom of the tubing and as the pressure builds in the well, the produced fluids are forced past the plunger into the tubing while drive gas and pressure differential are stored in the casing.

When sufficient gas and pressure are accumulated in the casing to achieve the critical velocity necessary to produce the fluid slug and plunger to surface, the flow line is automatically opened, allowing the plunger to cycle. The plunger then acts as an interface between the slug of liquid above it and the gas below to prevent "fall-back" of the liquids into the wellbore.

See Figure 1.

EQUIPMENT REQUIRED AND NEW TECHNOLOGY

As mentioned above, in the past few years the technology of equipment used in plunger lift has advanced in both engineering and materials. A few of these are listed. (See Figure 2)

Plungers

Better Seals: New seal designs make it possible to form a more efficient seal between the plunger and the tubing wall to prevent gas slippage or fluid passage, allowing marginal wells to be candidates for plunger lift.

Abrasive Application: Plungers have been designed to withstand the abrasion of sand and coal fines.

Paraffin Cutters: These tools are designed to provide good seals and act as paraffin cutters in wells where the expanding pad plunger becomes ineffective. The combination plunger with a paraffin-cutting element on top and the expanding pad on bottom has been quite successful.

Bypass: Tools with a bypass valve have been improved, allowing the plunger to return to the seating nipple faster in order to reduce the downtime needed to make the next cycle.

Double Element: Plungers with double element pads have been developed where a positive seal is needed. They are designed to operate in tubing that has been on rod pump where rod cut is present; i.e. the bottom seal holds the seal while the top seal passes the rod cut collars.

NOTE: Manufacturers are designing and manufacturing plungers shorter, lighter, more durable and with the specific needs of the producer in mind. No single plunger is the "cure all" -- each application is evaluated for the proper tool.

Lubricator and Flow Outlet

Some manufacturers have designed their lubricators so as not to restrict flow on plunger arrival. Older lubricators were designed so that the plunger arrival would restrict production flow and, in this case, a dual outlet was required.

Catchers

Catchers with a positive latch position are available and are designed to operate with any manufacturer's plunger, regardless of the style.

Motor Valve

Motor valves open and close the flow line when conditions have reached operating parameters.

Downhole Shock Assembly

The downhole shock assembly, which is usually seated in a seating nipple, is used to cushion the fall of the plunger on the return trip to the bottom of the tubing string.

Shut Off on Arrival (magnetic shut off or plunger cycle counter)

Technology has been developed for a new style magnetic shut off or plunger arrival sensor. The new style electronic device clamps to the tubing and creates a magnetic field. When the plunger arrives, the magnetic field is changed through the mass of the plunger, and a signal is given that the plunger has arrived. This MSO can be used on any manufacturer's equipment and does not require a special connection on the catcher or lubricator.

Pressure Sensor Switch Gauge

This gauge is used to open or close the well based on preset pressure criteria.

Controllers

The advances in electronic controllers in recent years have been the most dramatic of all the advances in plunger lift equipment. These new generation controllers, depending on the application required, include electronic timers with on and off cycles, on and off cycles with a delay cycle, both with pressure options, as well as the computer controller that makes automatic adjustments based on well conditions and plunger arrival time. Most controllers can be installed with solar panel systems that keep the batteries at full charge.

In summary, the advancements made in electronic controllers and plunger designs have vastly increased the number of wells that can be lifted with a plunger system. Marginal wells or wells that are uneconomical to produce can now be produced with plunger lift.

QUALIFYING A WELL

There are two qualifications to consider. The conditions of a well that qualify it for plunger lift are simple. First, look at the gas/liquid ratio in relationship to the depth of the well. Every form of lift has its rule of thumb and, for plunger lift, it takes 300-500 cubic feet of gas to lift one barrel of fluid 1000 feet, depending on the weight of the fluid.

Light crude will require fewer cubic feet per 1000 feet of lift than will heavy brine water. So, if one wanted to produce a 6000-foot well with 20 barrels a day of heavy fluid production, he would need approximately 3000 cubic feet of gas per barrel. To lift the 20 barrels would require 60 Mcf a day.

The other qualification is related to the bottomhole pressure. The well's formation pressure must have the ability to overcome the weight of the plunger and slug of fluid and produce it to surface against the wellhead back pressure. Remember, this is a rule of thunb; most applications will have a much higher gas/liquid ratio.

See Figure 8 (adapted from Foss and Gaul curves).

This writing is directed more at the practical application and experience in lifting a well with a plunger system. For those interested in a more technical analysis of plunger lift operations, the author suggests a paper written by James F. Lea (see References) which incorporates tubing size, casing pressure, tubing or back pressure, gas weight and friction, weight of the plunger, and fluid slug and slug friction, as well as gradients and velocities.

Like every form of artificial lift, the plunger lift method is not for every well, and certain conditions must be present for an operator to benefit from such an efficient method of lift.

APPLICATIONS

Unloading Liquids from Gas Wells

The most common use of the plunger is to unload the liquids from a natural gas well. When a gas well is first completed, the bottomhole pressure is usually sufficient to produce the well. As the well produces, the bottomhole pressure declines, the well loses the ability to lift the fluids to surface, and we experience liquid fall-back or loading.

The well will then begin to flow in slugs or heads. These slugs or heads restrict the ability of the well to produce at its maximum rate. The plunger installed in the well will act as the interface between the liquid slug and the drive gas, and will allow the liquid slug to be produced to the surface with minimum fall-back.

This well's production will increase because greater drawndown is achieved. If this well is neglected, and the slugs or heads begin to get heavier and further apart, the well will experience loading. In other words, the fluids in the tubing reach a point where critical velocity is not achieved to lift the slug to surface and, simply put, the fluids kill the well.

See Figures 1, 3, 4 and 5.

Gas Wells with Intermitters

Some operators use a method of intermittent lift on "loaded up" gas wells to blow the fluid slug to surface. This system of shutting-in a well, letting the pressure build up, and then opening the flow line is a way to produce some hydrocarbons from the wellbore without using any type of artificial lift.

Consider this: The one thing that caused the problem in the first place was the fall-back of the fluids into the wellbore when their velocity dropped below their critical point. Without an interface (plunger) between the slug of liquid and the drive gas, it will be necessary to shut-in the well for a longer time in order to build sufficient pressure to produce the critical velocity needed to flow the slug to surface.

Without an interface between the fluid slug and the drive gas, that well will still experience fall-back because of fluid sticking to the tubing wall and gas breaking up through parts of the slug. This well will lose a percentage of its potential for two reasons: (1) extended shut-in time to build sufficient pressure and (2) fall-back, which will result in less drawdown on the formation.

In other words, this wellbore will never be free of weight exerted by the liquids left in the well pushing against the face of the formation. In most cases, the intermittent lift system will be improved with the use of a plunger, and the life of the well will be extended.

See Figures 1, 4 and 6.

High Gas/Liquid Oil Wells

Operators are discovering that some formations, when first completed, make sufficient fluid to justify a rod pumping system. However, as the well continues to produce, the fluid volumes decline and the gas/liquid ratio increases. As the gas-to-liquid ratio increases, it becomes more and more difficult to produce the well because of gas interference. This gas interference results in mechanical failures in the form of gas lock, fluid pound, rod parts, tubing wear, stuffing box failures, and downtime.

This well may be a prime candidate for a plunger lift system. If a well on a rod pump meets the requirements for a plunger lift system, the operator can change out his artificial lift system, alleviate these mechanical problems, and utilize his rod pumping unit on another well.

The author has seen several cases where a high GLR well being rod pumped has increased overall production utilizing a plunger system. These wells experienced a substantial savings in operational cost due to reduced mechanical failure and energy cost to operate the pumping unit.

See Figures 4 and 7.

Removing Paraffin

Some wells make paraffin, and depending on the bottomhole temperature, hydrocarbons will cool to a point that the paraffin will collect in the production string. Paraffin formation in the tubing will act as a plug or restriction and reduce the velocity at that point. If the restriction is sufficient to reduce the flow below the critical velocity, the well will experience fall-back, and load up with liquids and restrict production.

A specially made plunger with paraffin-cutting rings is utilized to cut the paraffin build-up on the inside diameter of the tubing so the production string is kept clear of restriction. The frequency of plunger cycle in these wells depends on the speed of paraffin build-up and whether the well's condition requires the plunger to also be used to lift a slug of liquid to the surface.

Some operators have discovered that a plunger lift system reduces the cost of paraffin maintenance of these type wells and, at the same time, it increases production because of reduced friction and downtime experienced during the conventional paraffin removal procedures.

Gas Lifting with Plungers

Some operators who have gas compression available, are using a plunger in conjunction with a gas lift valve to act as an interface between the oil slug and the injected gas used to lift the plunger and slug to the surface.

With a packer set just above the perforations, a gas lift mandrel and valve are located above the packer in the production string. A collar stop or tubing stop with a shock assembly is set in the tubing above the gas lift valve. Gas injected into the casing passes through the gas lift valve below the plunger and forces the plunger and slug to surface. The injected gas is separated and recompressed for the next lift cycle.

This method of using injected gas to lift the plunger allows a small compressor to supply the energy to lift several wells. In this form of plunger lift, it is advisable to install a standing valve below the point of injection to prevent the injected gas and produced fluid from being forced back into the formation.

CONCLUSIONS

The author has experienced plunger lift system installations on all the different applications discussed in this article and, in most cases, each operator was amazed at the efficiency of operation. Production, depending on the application, was substantially increased. The lease operator's (pumper) time required to produce the well was decreased.

The original cost of installation was much less than with conventional methods. The energy cost to operate the well was greatly reduced and, in the event a rod pumping system was replaced, the operator eliminated rod parts, tubing wear, downhole pump repair, electricity charges, or gas engine repair.

Again, it is emphasized that if an operator has wells that will produce themselves with their own energy, there is not a more efficient or economical method of artificial lift than the plunger lift system. An operator will be money ahead to consider all types of artificial lift before making his selection, and letting the well do the work should be close to the top of the list.

REFERENCES

Lea, James F.: SPE Paper 10253 "Dynamic Analysis of Plunger Lift Operations." November 1982, pgs. 2617-2630.

Foss, D. L. and Gaul, R. B.: "Plunger Lift Performance Criteria with Operating Experience -- Ventura Ave. Field." Drilling and Production Practices, API 1965, pgs. 124-140.

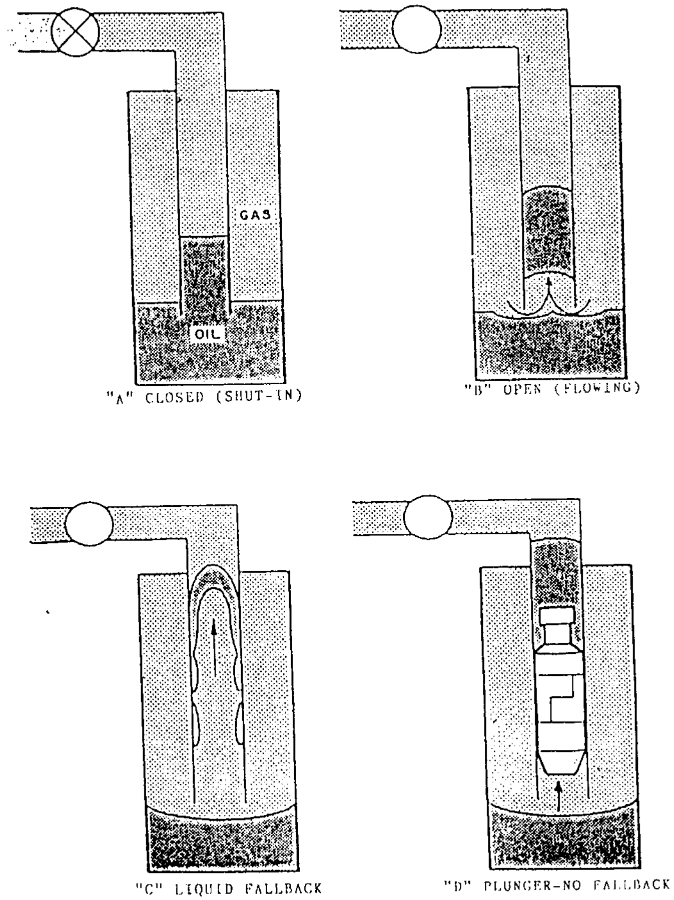


Figure 1 - Basic plunger lift mechanics

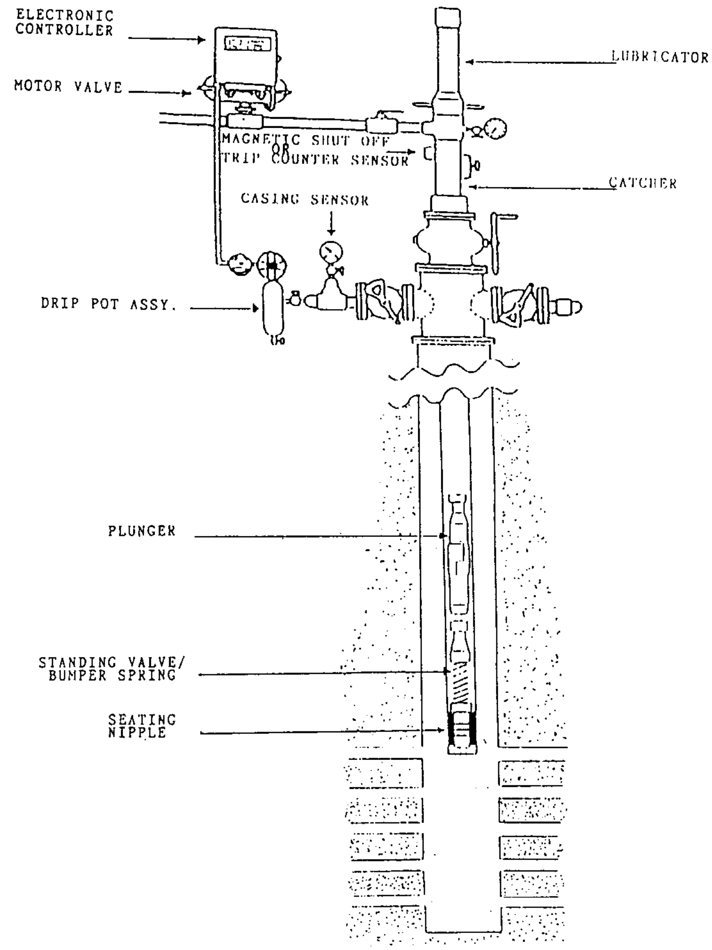
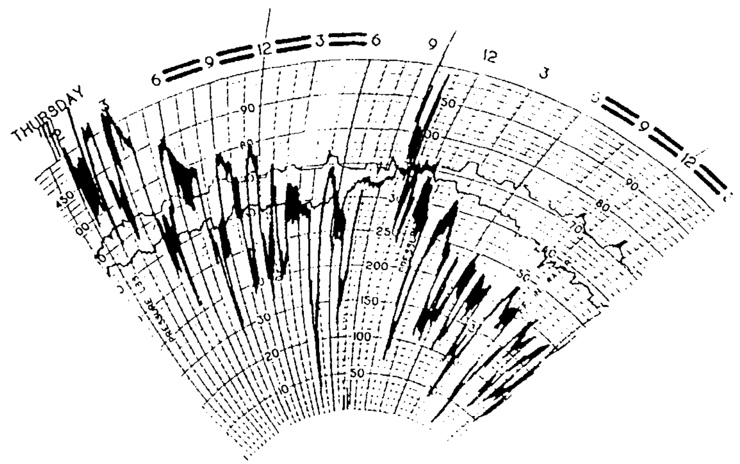
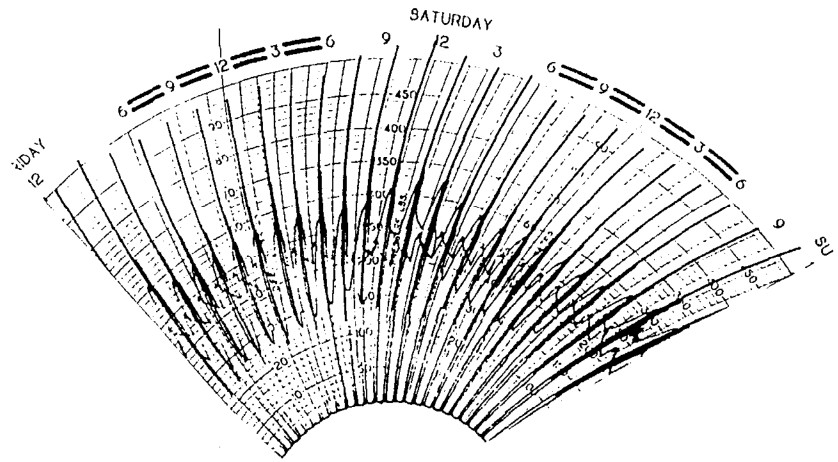


Figure 2 - Standard plunger lift installation



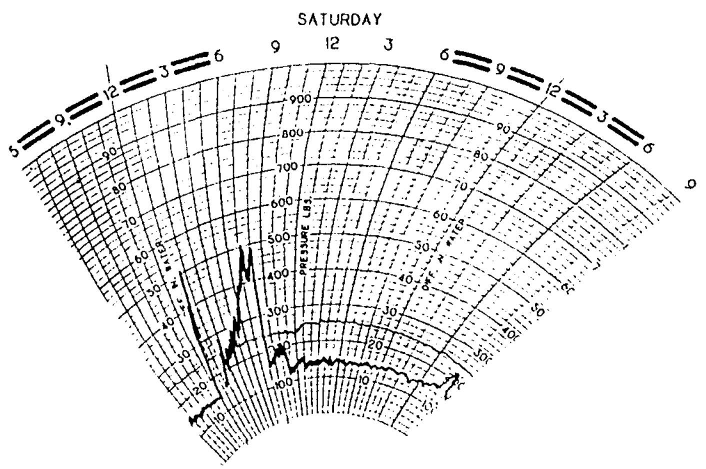
This figure depicts a well that is flowing in slugs and beginning to load up. Remember the rules of thumb in this article. If a plunger were installed in this well to unload the well cleanly a couple of times a day, gas production levels would be higher and more consistent.

Figure 3 - Gas well flowing in slugs



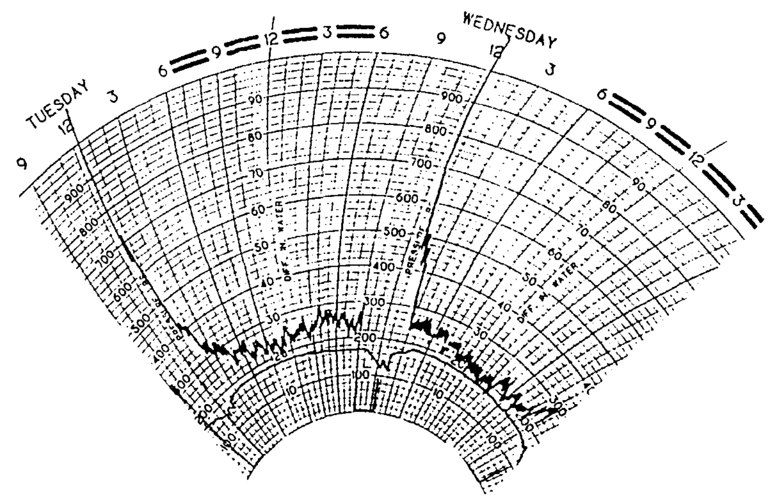
This figure depicts a well on plunger lift that makes a good deal of fluid. Notice the well is not allowed to flow back to line pressure, but energy (gas) is saved to lift fluid from wellbore. As fluid production declines, flow cycles are lengthened to sell more gas and keep well unloaded. Notice first peak on chart is well being opened up and second peak is gas flow after plunger arrival.

Figure 4 - Gas well with plunger lift system



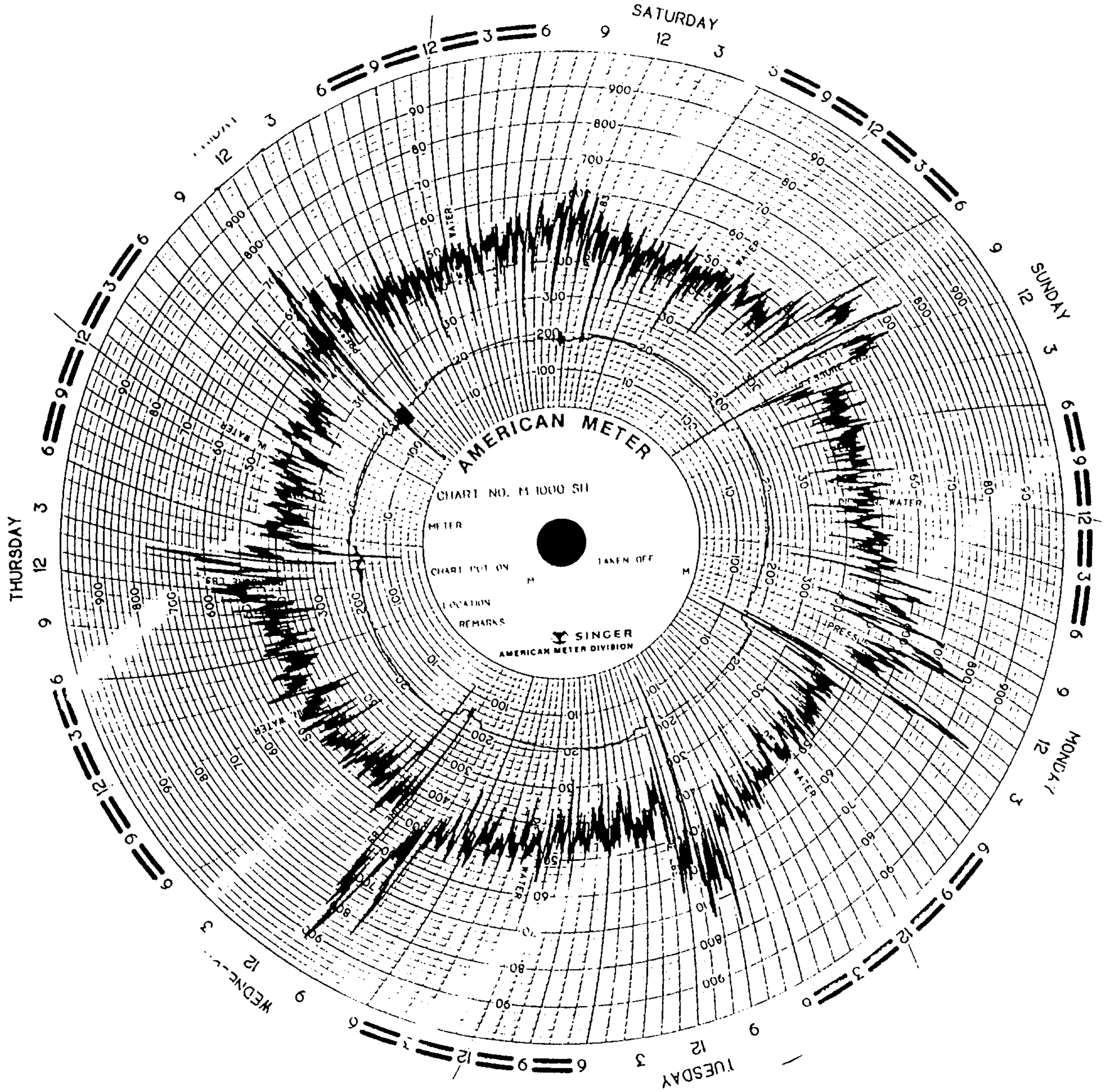
This figure depicts a flowing well intermitting itself, whenever there is sufficient pressure build-up to unload a slug of liquid. Then the well falls back to riding the line until enough pressure builds to start the cycle over again. In this case, production of this well is severely retarded by liquid fall-back.

Figure 5 - Gas well flowing in slugs, loading up



This figure depicts a well on intermitter control only. Note that this well falls back to riding the line quickly because fluids are not cleared from the tubing and fall back to load the well.

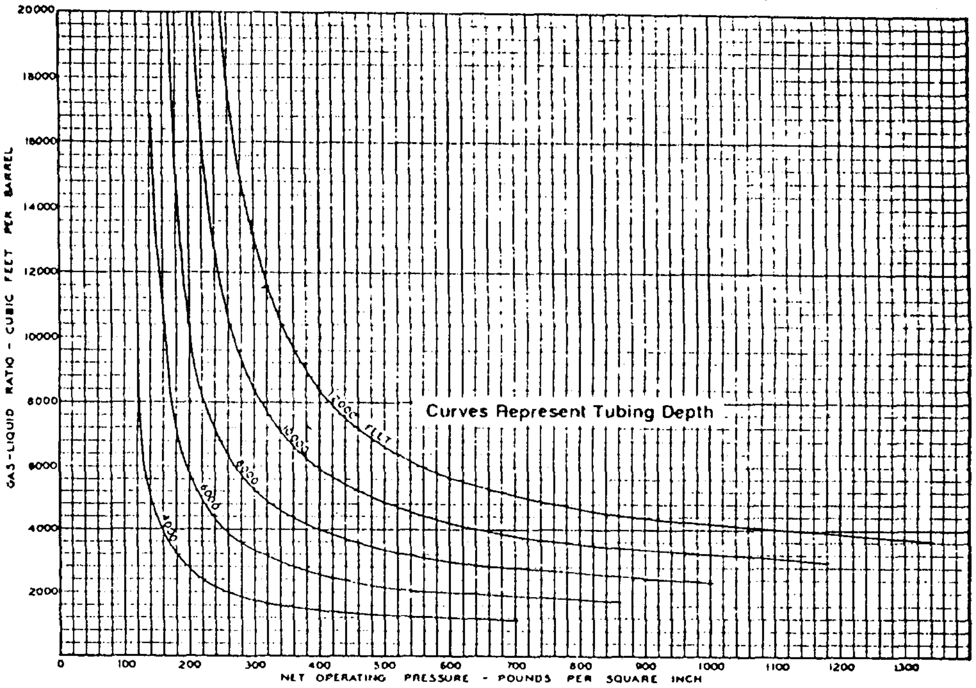
Figure 6 - Gas well on intermitter control



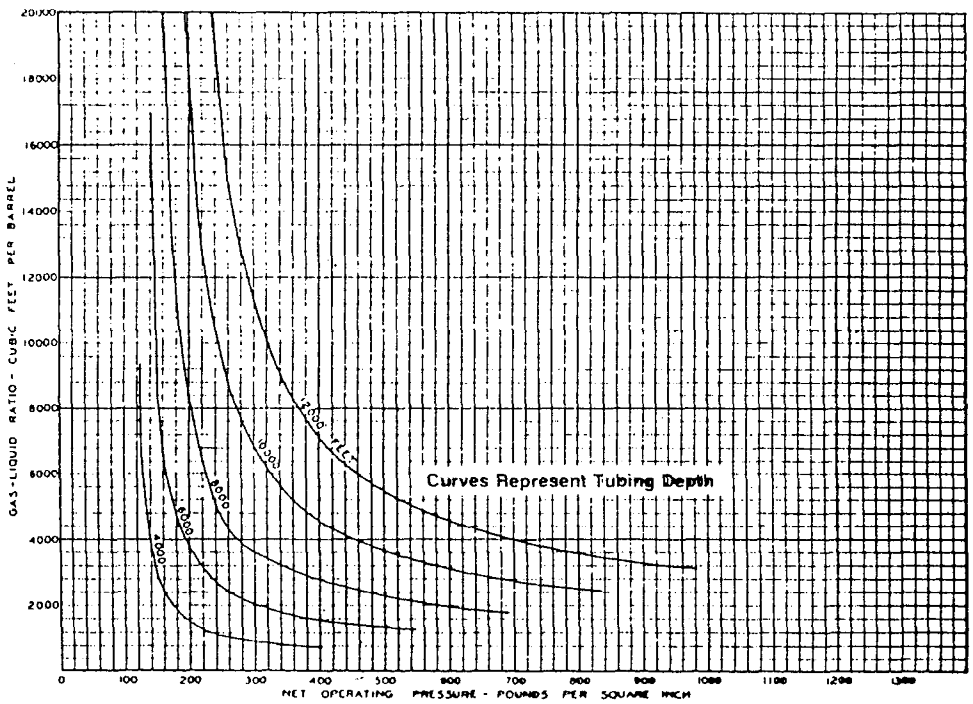
High gas-to-liquid ratio rod pumping wells, as depicted above, that pump off and flow are good candidates for plunger lift. The economics are in energy savings, equipment wear and labor savings.

Figure 7 - High gas-to- liquid ratio rod pumping wells

Gas and Pressure Requirements — 2-in. Tubing



Gas and Pressure Requirements — 2½-in. Tubing



Net Operating Pressure = $P_{Csg.} - P_{Sep.}$

To use these curves, find the well Gas-Liquid Ratio at the left. Draw a line to the right to the curve that represents tubing depth. Then draw a line down to the Net Operating Pressure Requirement at the bottom of the graph. These curves are provided as a guide to assist in defining the suitability of wells for plunger lift systems.

Figure 8 - Plunger lift application curves