

New and Unusual Applications for Plunger Lift System



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Abstract

As plunger systems become more sophisticated and people become more familiar with them, their credibility and usage is increasing. As a consequence, the spectrum of applications for these systems has begun to increase. In the opening pursuit of lower lifting costs and reduced capital spending, creative engineering techniques have applied the principle of the plunger to some unique production problems. The purpose of this paper is to present a number of these along with some case histories.

The normal applications for a plunger are for Gas Wells, Hi-Ratio Oil Wells, Intermittent Gas Lift and Paraffin Removal.

Now, however, plungers are also being used to:

1. Produce liquids in extremely low pressure reservoirs
2. Produce liquids in retrograde condensate wells
3. Remove water from coal seam methane gas wells
4. Prevent paraffin buildup in dual one wells
5. Prevent paraffin buildup and increase lift efficiency in deviated gas lift wells with wide perforated zones
6. Remove liquids from wells with no tubing
7. Prevent down hole freezing problems in high pressure gas wells
8. Remove water from wells in CO₂ injected formations

Another application that appears to be highly probable is liquid removal from CO₂ source wells.

The major obstacle to more widespread utilization of plungers has been a lack of education. This has been a problem not only with operational personnel, but engineering and management as well.

Hopefully, these additional applications along with the present increase in usage will make people even more cognizant of the potential savings offered by the plunger-lift system.

Introduction

Production engineering has become more of a challenge with the advent of lower petroleum product prices and sharply

reduced drilling programs. The problem is to minimize capital spending and maximize results from existing production. Many wells now are going to need some form of artificial lift and many wells now lifting will reach economic limit because of high lifting costs.

Awareness of additional uses for the principle of the plunger may assist Engineering and Management in achieving these goals on some of their wells.

Producing Liquids In Extremely Low Pressure Reservoirs

Until the advent of the light weight, high efficiency seal plunger most applications were limited to wells with reasonably high bottom hole pressures. This improvement has allowed plungers to operate in many reservoirs that would not have been candidates before.

Presently, there are plungers operating in several areas with reservoir pressures that would have previously been considered too low.

The Sussex and Shannon Formations at 4000' in Central Colorado have many wells that respond to plunger operation. Normally completed with 2-3/8" tubing, these wells are sustaining plunger operation with less than 100 psi on the casing and producing into a 20 psi sales line.

In Northeastern McClain County of Oklahoma there are numerous wells utilizing plungers in the Osborne Formation. These wells are 8900' in depth completed with 2-3/8" tubing and operating with 200 psi or less on the casing into a 35 psi sales line.

A major independent in Wyoming was having difficulty pumping some wells that had a pressure decline but were very gassy. The operator was able to extend the economic limit of the wells by replacing many of the pumps with plungers (Table 1). These wells are at 10,000' and completed with 2-7/8" tubing. They are operating the plungers with less than 200 psi on the casing, going into a 35 psi sales line. The attitude of the production foreman is as follows: "Looking over the well files, I see the same story---Our field came in as high pressure, high oil production and no water. In a very short time we still had some pressure but not enough to unload the wells. We ran rod pumps and brought our production up at first, but then we had trouble with gas locking. The oil here is real gassy and hard to pump. As we



ran plungers, our wells stabilized. We make mostly gas and a little oil off each plunger. We were told we should be plugged and out of this area by 1986! The plungers are still keeping us in business. We have 44 wells in this field. Fourteen wells are still on pump. Two wells are still flowing (we have to shut-in these wells one or two days a week) and the rest are on plunger. Of the 28 wells on plunger, 14 were changed over from pumping units. This field makes ± 200 BBLs oil per day and 5 MMCF gas per day. Not too bad for a group that was going to be gone two years ago. There are six people working out of this office and we like being here fine!" There are presently 70 wells on plunger in this geographical area.

Producing the codell: a retrograde condensate formation

The Codell is an extensive formation that covers a large area in Central Colorado. This zone is 6000-7000' in depth and when first completed will have bottom hole pressures in the 2000 psi range. Normally, this pressure will drop off to a much lower value after being produced over a relatively short period of time.

Initially it is desirable to maintain higher flowing pressures because the produced liquids exhibit a propensity to "flash" or change to a gaseous state at lower pressures.

There were several production problems encountered. As the well pressure declines, the well begins to load up and die. The high gas liquid ratio makes pumping the well unfeasible. Also, the economics of the completion will not support the high lifting costs associated with the pumping operation.

As the well pressure and production declined, plungers were installed. Their operation seemed to lend itself well to the high gas liquid ratios and lower pressures (Fig.#1).

A typical operation opens the well when the casing pressure increases to a proper value to lift the column of liquid that has accumulated. As the plunger arrives at the surface, the well is shut in after a short period of after-flow to bring in more liquid for the next cycle. It is becoming increasingly popular to co-mingle the Codell with the Niobrara Formation which has a lower pressure and a lower gas liquid ratio.

Liquid Removal From Coal Seam Methane Gas Wells

A major producer in Southwest Colorado and Northern New Mexico encountered liquid loading problems while producing methane gas from a coal seam formation at 3500'.

Several methods, including plungers, were applied to the problem for evaluation. After a three month comparison,

plungers were found to be quite effective in handling produced liquids up to 180 BPD. Coal fines were also present but did not present a problem for the plungers.

Production over the entire field declined during the study, but plungers compared favorable for several reasons:

1. Wells produced by plungers showed less of a decline than the overall field.
2. Lifting costs were dramatically reduced (Fig.#2). These costs included rig time, man hours, fuel cost, maintenance and downtime.
3. Investment costs were considerably less (\$5-6,000 for plunger vs \$20-25,000 for beam pump).

The plungers have been in operation for a year now and are considered to be a cost effective method of removing liquids from coal seam wells up to certain liquid volumes.

Preventing Paraffin Buildup & Increasing Lift Efficiency In Dualzone Wells

A large international independent operator in Zaire was faced with a severe buildup of paraffin and loading problems in many of their producing wells. After unsuccessfully experimenting with several other methods, the plunger was considered.

An unusual mechanical configuration combined with a special type plunger solved not only the paraffin problem, but assisted in producing another zone more efficiently.

A low pressure, low GLR, deeper oil zone was communicated with a higher gas zone in the following manner; (Fig.#3) A packer was set above the lower (oil) zone and below the upper (gas) zone. Another packer was set above the upper (gas) zone with a side pocket gas lift mandrel between the two packers. The mandrel was used to communicate the upper zone with the lower zone.

Installed in the mandrel was a "dummy orifice" with a reverse check valve and 10/64" orifice. This arrangement allowed flow from the upper zone into the production string, but prevented any flow from the tubing and the lower oil zone into the upper zone. A standing valve below the bottom packer prevented any flow from the upper gas zone back into the lower oil zone via the tubing.

A stop and spring was installed above the upper packer. This permitted the plunger to travel between there and a lubricator on the surface. Well flow was controlled by an electronic controller and motor valve on the flow line. In order to maximize well flow time and minimize shut-in time while cleaning the paraffin in the tubing string, it was necessary to



utilize a unique plunger design. When this plunger struck the lubricator at the end of its upward stroke, the plunger seals would retract and provide an annular bypass with a large flow area. This combined with a reduced coefficient of friction facilitated a rapid descent to bottom when the well was shut-in.

At the bottom of the stroke, the seals would expand and engage the walls of the tubing. The controller would reopen the well after only enough shut-in time for the plunger to reach bottom. The plunger, with its seals expanded would travel to the surface lifting any fluids that had filled in from the lower zone during the previous flow period. All paraffin would be wiped upward and out of the well. The inherent design of the plunger prevented any paraffin from being pushed downward on the next cycle.

Operation in this manner allowed the commingled zone to flow until the well attempted to load up. When the flow line would be closed by the controller, the upper zone would “charge” the casing annulus between the two packers with gas. The controllers would reopen the well and the plunger would return to the surface assisted by the volume of gas stored between the packers.

Preventing Paraffin Buildup and Increasing Lift Efficiency in Deviated Gas Lift Wells with Wide Perforated Zone

Just offshore in NW Peru there is a field with a shallow zone (4500’T.V.D.) that is very prolific and very thick (1500’). The wells are completed by drilling deviated (up to 50°) holes off of platforms. This method allows a wider drainage pattern and increased exposure to the zone per well.

The zone is being gas lifted, but the thickness of the zone creates a mechanical problem. Conventional packer arrangements below the operating valve would not allow drawdown over the large perforated interval. By attaching a second, smaller string of pipe to the production string, gas could be introduced through an operating valve at the bottom of the zone (Fig.#4). This afforded maximum drawdown on the formation.

Severe paraffin problems had plagued the operation since its inception. It was necessary to pull the tubing string and hot oil that plugged tubing frequently. This was very costly and caused an inordinate amount of down time. These problems were compounded by low gas lift injection pressures, high separator pressures and the presence of a small percentage of produced sand.

Plungers were installed above the operating valves with a standing valve below. As long as the operating valves continued to function, the well production increased and the required injected gas decreased (Table 2). Several factors contributed to this :

1. The plunger eliminated fall back and reduced the amount of gas injected
2. The absence of excess injected gas and the elimination of fall back increased formation drawdown and
3. The elimination of paraffin reduced back pressure and down time. Twenty-five wells were installed with this arrangement. The operator was able to realize not only a reduced lifting cost, but an increase in production.

Lifting Liquids From Wells With No Tubing

There are many wells that are approaching economic limit for several reasons. One would be because the well income can no longer sustain the lifting costs associated with pumping units or relatively expensive forms of lift. Some wells that have been successfully produced using a conventional plunger may have the well pressure decline to a point that the plunger can no longer function properly.

There is evidence that these wells can be helped and their economic limit be substantially extended by installing a plunger in the casing (Fig#5). The advantage afforded is to utilize the larger cross sectional area of the casing. This allows liquids to be lifted with lower pressures than in the production string.

A major independent in East Texas has installed this type of system in several wells near Henderson, Texas. The wells were on beam pump producing ±65 Mcfd and 4-8 BOPD from 8000”. The wells, however, were approaching economic limit because of high lifting costs.

The lifting costs for a typical well per year were as follows (excluding overhead and personnel):

Three Rod Jobs with Rig	\$10,000
Pumping Unit maintenance	3,000
Engine Repair	1,600
Welding on Beam Pump	700
TOTAL.....	\$15,300

Fuel costs were 15 mcf at \$4/mcf or nearly \$22,000. Even if gas had been \$1.50/mcf the cost would have been over \$8,000.



The total lifting costs for the well would be between \$2,000 and \$3,000 per month depending on the price of gas at the well.

Pumping units were removed and replaced with the Casing plunger systems. There was no measurable increase in production, but the casing plunger systems were able to sustain essentially the same production as the pumping units. Because there is no external power supply, no surface controls and only one moving part, the lifting costs were dramatically reduced. The only lifting costs for the casing plunger consisted of three or four cup changes per month for \$150-250.

Salvage value on each well was conservatively in excess of \$23,000. This included tubing, rods, pump, engine and tree. This was more than double the capital expenditure for the entire casing plunger system.

Prevention Of Downhole Freezing Problems In High Pressure As Wells Utilizing Plungers

Downhole freezing of hydrates in gas wells is a function of well pressure versus temperature. The higher the pressure, the higher the temperature at which freezing occurs. This becomes a hazard when a plug of ice seals off well flow. Pressure building up beneath the plug increases the temperature at which more ice can be formed and compounds the problem. Not only does the well lose production, but a safety hazard exists when attempts are made to remove the blockage. The problem was created primarily by a coal seam zone with cold water at 1700', which caused a temperature anomaly. This combined with low ambient temperatures presented favorable conditions for ice formation.

The initial solution was to continuously inject methanol into the well to discourage freezing. This proved to be very expensive. Plungers were being used to remove produced liquids and prevent well loading as flow dropped below critical velocity. High line pressures contributed to the loading problem.

Electronic Time Cycle Controllers were being used to control well flow and cycle the plunger on a combination of casing pressure buildup and flow time. The introduction of a second electronic controller enabled the operator to realize a considerable reduction in the chemical cost. By arranging the electronic controllers so that one controlled well flow and one controlled a pneumatic chemical pump (Fig.#6) it was possible to synchronize well flow and chemical injection. By

injecting the methanol for a short period into the tubing on top of the plunger when the well flow stopped, it migrated to the cold water zone and prevented the formation of solid ice.

The next run of the plunger swept this "slush" upward and out of the tubing string eliminating the potential for a problem while using only a fraction of the injected chemical.

Removing Water From Co2 Injected Wells

Presently there is a project by a major producer in West Texas to recover additional oil from a particular zone by injecting water and/or CO₂ into the formation.

Initially, water and CO₂ were injected into wells near the producing wells. The resultant produced liquids were gassy and difficult to pump. Plungers were installed and proved effective during this period.

The next phase of testing involved alternately injecting water then CO₂ in 20 day cycles. During the 20 days water injection period there was an insufficient gas to liquid ratio to sustain plunger operation in the producing wells.

Subsequently, it was decided to inject CO₂ into the casing/tubing annulus of the producing well during the 20 day water injection cycle. This would augment the produced gas to liquid ratio and should enable the plunger system to function properly.

Evaluation of these procedures is presently in progress.

Conclusion

Regardless of fluctuations in petroleum product prices, it will remain imperative that constant attention be given to prudent production practices. This includes reducing lifting costs wherever possible to extend economic limits.

Plungers are not a panacea for all production problems, but if applied properly can be very effective in reducing both capital expenditures and lifting cost. Combined with modern equipment and techniques, the unusual applications presented in this paper may encourage more production personnel to now consider this proven principle as a production system along with pumps, hydraulics and gas lift.

Acknowledgements

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TABLE 1

LOW PRESSURE RESERVOIRS

	BEFORE (PUMPING)		AFTER (PLUNGER-LIFT)		DEPTH
	BOPD	MCF/D	BOPD	MCF/D	
WELL #1	4	0	3	25.8	±10,000'
WELL #2	0	0	3	17.5	±10,000'
WELL #3	P & A CANDIDATE		2	12.5	±10,000'

AVERAGE PUMPING COSTS = \$1,200/Month

TABLE 2

PLUNGER-LIFT/GAS-LIFT SYSTEM
WIDE INTERVAL ZONE

	BOPD	GOR	GL CONSUMPTION	
July 27	30	4533	124	BEFORE
August 6	43	2511	109	
August 16	30	5400	132	
September 9	36	2111	131	
September 15	26	7000	88	
October 17	110	3100	234	AFTER
October 21	94	3266	181	
November 10	74	3324	127	
November 12	71	3155	162	
November 15	76	3200	136	



RETROGRADE CONDENSATE WELLS
(Codell-Niobrara)
PRODUCTION DECLINE CURVES

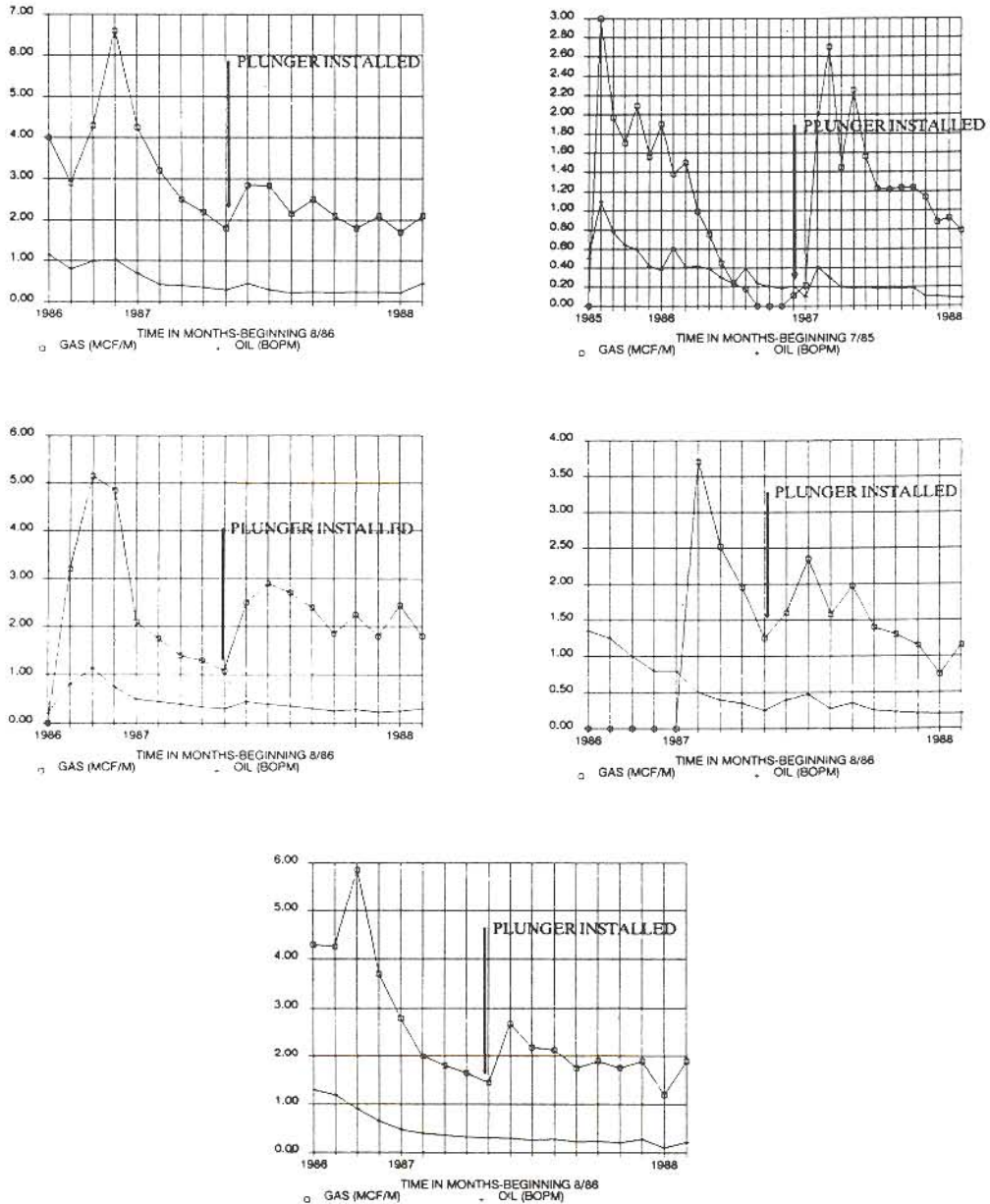


Figure 1.



COAL SEAM WELLS

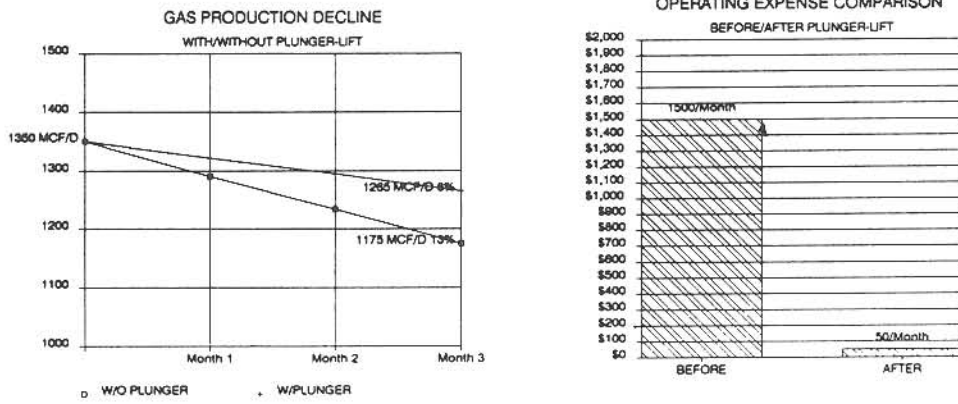


Figure 2.

DUAL ZONE PLUNGER-LIFT SYSTEM FOR CONTROLLING PARAFFIN AND INCREASING EFFICIENCY

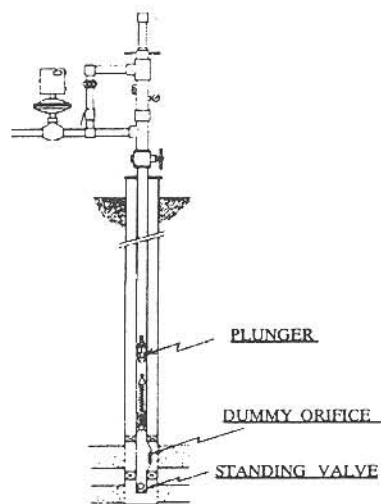


Figure 3.

PLUNGER-LIFT/GAS-LIFT WIDE INTERVAL ZONE

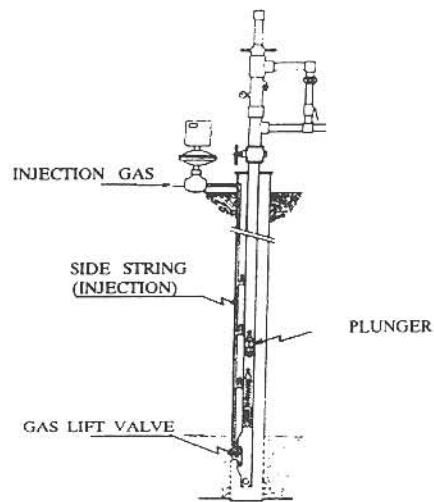
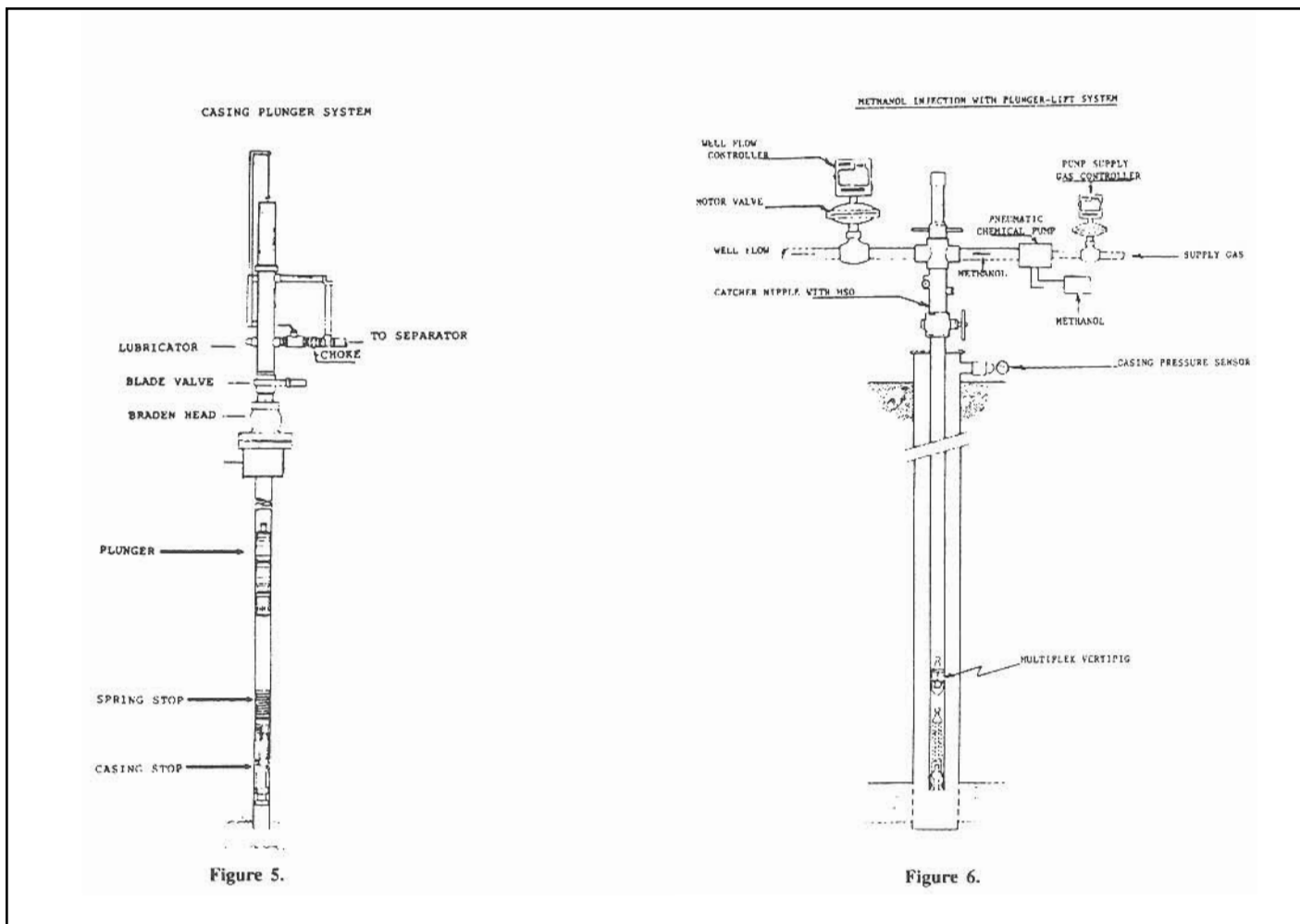


Figure 4.



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