EXTENDING ECONOMIC LIMITS AND REDUCING LIFTING COSTS; PLUNGERS PROVE TO BE LONG TERM SOLUTIONS

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ABSTRACT

Plungers have been considered by many operators as short term or intermediate solutions to liquid loading problems in gas wells and gassy oil wells. Data is presented in this paper indicating that some producers have routinely utilized plungers to stabilize production and keep wells producing for years at a nominal cost.

Well histories, production decline curves along with cumulative production reports will support the producer's case for utilizing the plunger system for such an extended period of time. Plungers, which are sometimes misapplied and often misunderstood, have been around for a long time. With the new state of the art equipment available and qualified personnel to educate operations people, plungers can be a valuable production system for many wells.

INTRODUCTION

The principle of the plunger has been in existence for over 60 years. The basic premise was that of a piston traveling within a cylinder with the cylinder being the production tubing. The purpose was to provide a seal between produced liquids and produced gas. It was determined that by cyclic operation of the well with the plunger traveling the entire length of the tubing, several benefits manifested themselves. One could stabilize well flow and production and by eliminating fallback, sustain average lower flowing bottom hole pressures. A secondary function of the plunger would be to prevent the buildup of paraffin deposits in the tubing.

The cyclic operation was accomplished by means of a mechanical timer or manual operation of the valves.

Unfortunately, the principle was sometimes not fully understood. It resulted in many cases of misapplication and improper operation. Also the early equipment that was available tended to be quite rudimentary. The plunger was often no more than a grooved bar that required high pressure differentials to travel. The surface controller was a crude mechanical timer with limited dependability and cycles were often arrived at by trial and error.

Over the years the plunger acquired a reputation for being very labor intensive and undependable. Problems that arose from misunderstanding, misapplication and improper operation were all too often blamed on the equipment and the plunger principle itself. Plungers were considered by some to be a last resort and put on wells that were marginal applications, at best. As a consequence, to some operators, plungers were a source of disappointment and propogated a negative attitude toward them.

Plungers were also considered to be a short term, interim solution at best. This resulted in many wells where a much more expensive production method was utilized because it was believed it was needed eventually anyway.

Even as the equipment improved over the years, there was still a negative connotation connected with plungers in many sectors.

Fortunately, this attitude was not held by everyone. An executive with a large independent operator put it thusly, "I think a major problem surrounding the effective use of a plunger is perhaps what production people, engineers thru pumpers, first get in their mind what a plunger lift will do for their well. I don't know if that preconceived idea is put there by salesmen or articles in trade journals or what, but I do know if a plunger lift does not perform up to those expectations, right or wrong, that installation is doomed".

The purpose of this paper is to demonstrate that with the proper application, plungers can provide a long term, inexpensive production method that is also very low in capital expenditure.

ECONOMIC LIMITS

When capital expenditures and maintenance are reduced and fuel costs are all but eliminated, there is a significant change in the economical limit for a given well.

The following examples demonstrate that plungers are not only effective in producing their wells inexpensively but exhibit some additional benefits as well.

It was usually assumed that wells with accelerated decline curves would merely return to the normal decline once the liquid loading problem was addressed. The installation of plungers not only increased the production, but sustained this increase over a long period of time. It has been observed in many cases, the rate of decline has actually changed, extending the life of the well dramatically. This stabilization of decline gives credence to the fact that plungers are capable, when operated properly, of achieving long term results. The cumulative production figures versus the lifting costs reaffirm the impact on the economics.

These wells are from different operators, different formations and geographical areas, but they exhibit one thing in common. Management and operating personnel have recognized and made a conscious effort to maximize the benefits from this cost-effective solution to a production problem.

A LOOK AT OPERATING COSTS

A large producing company has been using plunger lift for their wells in North Texas and have shared their information on expenses with us. The wells selected are from different producing formations to generate different conditions. A close analysis of the data verifies the economic advantage of plunger lift versus other forms of lift.

The data covers an eight year period, 1980 thru 1987. This time frame includes some production expenses before the wells were put on plunger lift to compare with the additional cost of operating the plunger. The actual cost in some cases goes down because of the increased production but as the wells decline, and production drops back to the level of natural flow, the operating differences are found to be minimal (Well #1 & Well #6).

As presented, the produced gas data is the NET monthly average during the designated year. The production is in gas only, and oil or condensate revenue is not considered even though most of the wells make some hydrocarbons. The footnote on water disposal is based on $1.00 per barrel and is included in the EXP.$ line. It is shown as such to depict the water production.

It should be pointed out that these expenses are operational expenses and do not include taxes or administrative overhead. Also capital costs are not considered in these figures.

The operating expense (Exp.$) is a total of seven expense catagories: Labor with benefits, chemicals, fuel-power, transportation (pumper), compressor, disposal and other. In addition, a group of five Maintenance and Repair catagories are included. They are, instrumentation, site and location, surface equipment, pump and tubing, plus casing and well bore are included. The plunger M&R is considered part of "pump and tubing" but is shown in the line, PLUNGER $, for observation.

All of these catagories are individually summed up at the end of each year and amortized over the 12 month period. The total of these averages establishes the operating expense (EXP.$). This expense when divided by the NET average gas production, results in the (EXP.$/MCF) line.

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WELL #1
CLASS: GAS PROD. EQUIP.: 2-7/8" X 7" TUB/SET: 10,408'
COMPLETION DATE: 12/77 PLUNGER INSTALLED: 8/82
PRODUCED GAS:FLOWING 203,928 MCF PLUNGER: 135,925 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	2462	2154	2597	2921	3992	3307	2150	1878
EXP.$	159	262	81	101	144	98	201	208
EXP.$/MCF	.05	.09	.03	.03	.03	.03	.09	.11

PLUNGER $	-	-	0	2	33	0	11	11

*AVERAGE WATER DISPOSAL COST: $25.00/MONTH

WELL #1 - Note - EXP.$/MCF declined after installation of the plunger and when the gas production returned to the 1981 level the EXP.$/MCF cost remained the same as natural flow.

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WELL #2
CLASS: GAS PROD. EQUIP.: 2-3/8" X 5-1/2" TUB/SET: 6,694'
COMPLETION DATE: 5/70 PLUNGER INSTALLED: 9/81
PRODUCED GAS:FLOWING 787,225 MCF PLUNGER: 93,864 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	2454	1640	1624	2084	1512	1320	1408	1499
EXP.$	387	272	847	357	302	329	289	254
EXP.$/MCF	.16	.12	.54	.17	.20	.25	.21	.17
PLUNGER $	-	0	597	67	38	38	21	11

*AVERAGE WATER DISPOSAL COST: $124.00/MONTH

WELL #2 - Note - There was some difficulty in stabilizing the plunger performance in 1982.

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WELL #3
CLASS: GAS PROD. EQUIP.: 2-3/8" X 4-1/2" TUB/SET: 7,385'
COMPLETION DATE: 8/76 PLUNGER INSTALLED: 10/82
PRODUCED GAS:FLOWING 73,293 MCF PLUNGER: 76,392 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	876	772	907	1903	1564	1221	872	806
EXP.$	133	299	147	295	336	157	297	244
EXP.$/MCF	.14	.33	.16	.15	.20	.12	.35	.28
PLUNGER $	-	-	0	46	107	13	48	13

*AVERAGE WATER DISPOSAL COST: $35.00/MONTH

WELL #3 - Note - A good increase in production dropped the EXP.$/MCF.

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WELL #4
CLASS: GAS PROD. EQUIP.: 2-3/8" X 5-1/2" TUB/SET: 7,663'
COMPLETION DATE: 12/77 PLUNGER INSTALLED: 6/82
PRODUCED GAS:FLOWING 302,772 MCF PLUNGER: 207,323 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	4424	3349	4294	5383	4540	4521	4299	3785
EXP.$	134	142	386	204	212	287	229	656
EXP.$/MCF	.02	.03	.08	.04	.04	.06	.05	.16
PLUNGER $	-	-	94	25	38	71	0	20

*AVERAGE WATER DISPOSAL COST: $25.00/MONTH

WELL #4 - Note - Put on compression with 3 other wells in March, 1987. Amortized cost $421/MO.

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WELL #5
CLASS: GAS PROD. EQUIP.: 2-3/8" X 4-1/2" TUB/SET: 7,739'
COMPLETION DATE: 9/75 PLUNGER INSTALLED: 11/81
PRODUCED GAS:FLOWING 535,323 MCF PLUNGER: 362,424 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	4138	4408	6266	5417	4687	4400	4820	4613
EXP.$	144	60	349	186	277	174	205	224
EXP.$/MCF	.03	.01	.05	.03	.06	.04	.04	.05
PLUNGER $	-	0	206	25	44	6	22	0

*NO WATER PRODUCTION / OIL PRODUCTION AVERAGE 22 BBL/MO.

WELL #5 - Note - Very little change in lift cost over extended period. Decline curve has changed considerably.

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WELL #6
CLASS: GAS PROD. EQUIP.: 2-3/8" X 5-1/2" TUB/SET: 10,736'
COMPLETION DATE: 3/77 PLUNGER INSTALLED: 12/81
PRODUCED GAS:FLOWING 483,601 MCF PLUNGER: 280,083 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	5672	2646	6020	4833	4045	3369	2482	2291
EXP.$	230	349	335	573	618	379	400	321
EXP.$/MCF	.04	.13	.05	.12	.15	.10	.16	.14
PLUNGER $	-	0	0	247	267	6	79	59

*AVERAGE WATER DISPOSAL COST: $50.00/MONTH

WELL #6 - Note - This is a classic application of plunger lift. The rapid production decline is changed when a plunger is installed. (See FIGURE ONE)

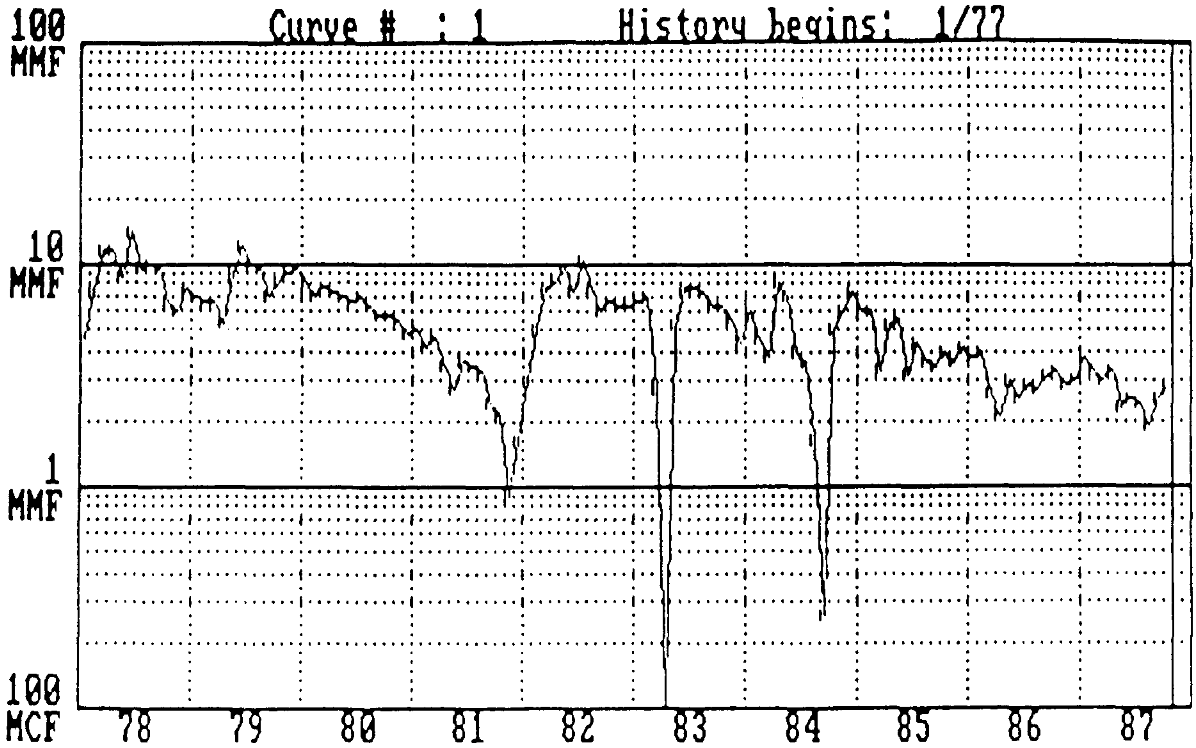

FIGURE ONE

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WELL #7
CLASS: GAS PROD. EQUIP.: 2-3/8" X 5-1/2" TUB/SET: 10,479'
COMPLETION DATE: 2/76 PLUNGER INSTALLED: 11/81
PRODUCED GAS:FLOWING 1,630,979 MCF PLUNGER: 589,641 MCF

MONTHLY AVERAGE

YEAR	'80	'81	'82	'83	'84	'85	'86	'87
PROD.MCF	16490	12757	12647	10026	9027	6355	6178	4907
EXP.$	517	518	321	256	406	297	475	558
EXP.$/MCF	.03	.04	.03	.03	.05	.05	.08	.11
PLUNGER $	-	0	81	0	38	21	0	118

*AVERAGE WATER DISPOSAL COST: $114.00/MONTH

WELL #7 - Note - A strong well with a flattening of the decline curve.

HOW LONG WILL THEY LAST?

Two Well Histories:

The price of gas was $0.10/MCF and oil was selling for $2.35/BBL. An oil operator drilled a 6200' Canyon Creek well near Sweetwater, Texas. The year was 1960. After flowing for three years, the well started heading and production was erratic. At the time there were no gas markets so the gas was being flared. Production had dropped to 10 Barrels a Day and the decision to "try a plunger" was made. In 1964, a plunger installation with all the bells and whistles, cost about $1100 including service and mileage. Today, a plunger is still operating in the well and producing fluid at the rate of 4-1/2 B/D. A gas market was established in 1966 and since then the well has produced 53 MMCF of gas.

Through 1987, the well has produced 85,082 Barrels of Oil; the surface equipment is still the original controller, motor valve and lubricator. Recently the standing valve and bumper spring were replaced. The number of plungers used during this 25 year period is not available, but if it were the cost of a plunger a year, $695, that's not much expense. There has been no paraffin scraping cost. The tubing has never been pulled. No compressor. No fuel or power cost. Just run the oil.

The decline curve for this well is shown below but only the last 20 years were printed. The larger of the dips in the curve probably represent periods when the plunger needed attention.

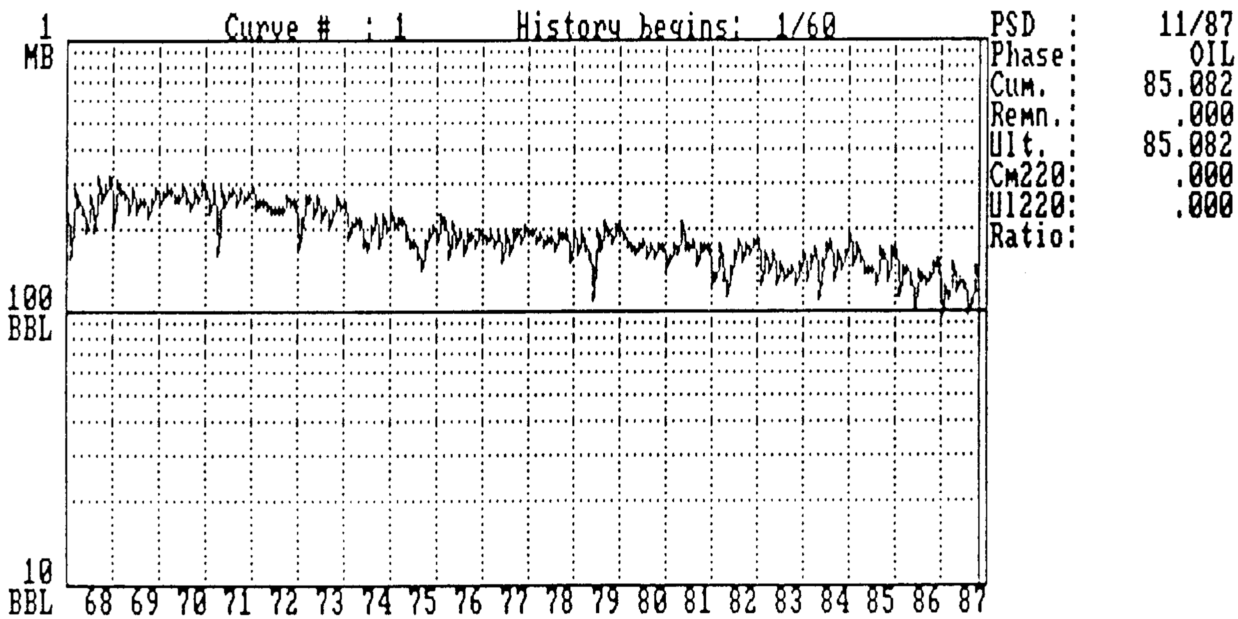

FIGURE TWO

Another history of interest is a gas well drilled in 1953. A Travis Peak completion with about 50' of pay at 6195'. Initial production was 2324 MCF/Day with 60 Barrels of condensate per million cubic feet. The well was sold in 1958 after producing 2199 MMCF. The new operator continued to produce the well until 1973. By this time the well had produced 5260 MMCF and a large amount of condensate. There was a group of wells in this area that were difficult for the operator to produce so he decided to sell. Shutin casing pressure had dropped to 420 psi.

The new purchaser was Vernon Faulconer of Tyler. Over a period of time he was able to evaluate the package he had purchased and disposed of all but two wells. Together these two wells have produced over 2.5 BCF of gas. The one used as an example here has produced 1427 MMCF and could have produced more if it had not been curtailed. The other well has produced in excess of 1200 MMCF during this time but the most unusual part is that the WHSIP has remained at 420 psi. Does that extrapolate to another 2.5 BCF?

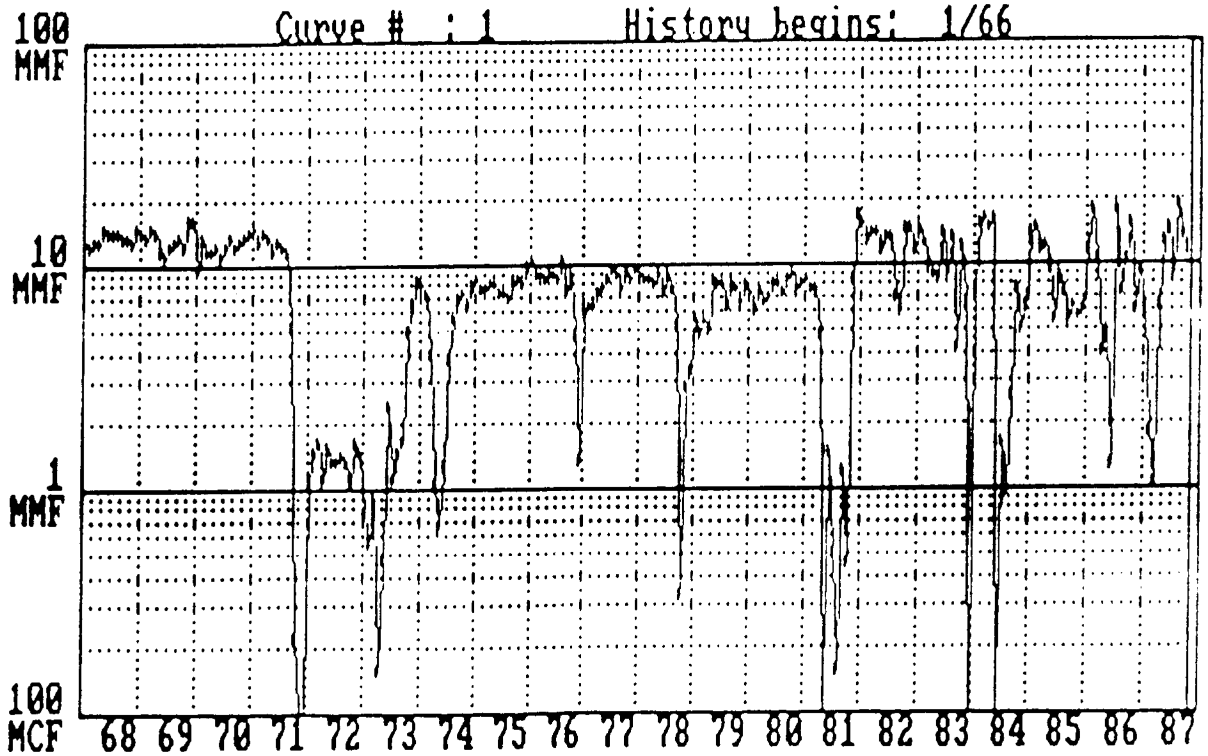

FIGURE THREE

When purchased, the wells were already equipped with individual compressors. To operate a plunger against a compressor is difficult but Mr. Faulconer's field people persisted and overcame the problems. Their learning curve can be seen on the decline curve above during the latter part of '83 and early '84.

In these wells, like the other example, nothing was done except to add the plungers. There has never been a rig on these wells since they were purchased. The compressors and controls were modified to accept the surges associated with plunger lift. Other than that, there were no other changes.

The Vernon Faulconer Company now operates over 250 producing properties and 95% are on plunger lift. Sixty percent of these are single well, single compressor installations. His success has been credited to the close attention each well gets everyday. The pumpers are trained on plunger operation and go through a checklist at each well everyday. His approach is to invest in Preventive Maintenance rather than the Maintenance and Repair which sometime equates to lost production.

CONCLUSION

With the economic climate as it is today, there should be even more impetus to consider plungers as the preferred production method where they are applicable.

There is available now a more scientific method of determining which wells have the proper producing characteristics to assure plunger operation. With this method it is also possible now to predict flowing bottom hole pressures and resultant well performance.

The equipment available today is much more sophisticated than was available when the historical example wells were installed. The advent of the electronic controller, in particular, has ushered in a new era of well operation. It now is possible to allow well response to dictate the opening and closing of the well. This ability, combined with time, allows cycles to be determined through pressure changes of the well and external factors such as line pressure. Positive pressure values and differentials between casing and tubing, tubing and flowline and flow rate in inches of water can be utilized to achieve maximum results. On the horizon are remote well head controllers that respond to changes by allowing algorithims to make some basic decisions.

Plungers that operate with much lower differential pressures are now available. Because of higher seal efficiencies and lighter weight, the plungers can operate at lower pressures and allow further drawdown of the well. Maximum operating casing pressures of 75-100 psi are not uncommon on wells 10,000' deep. In many cases, this allows the well to be produced to economic limit since very little further drawdown could be accomplished with another method. The well productivity index and reserves would need to be substantial to warrant the additional expense.

Most operators utilizing plungers successfully as a production method usually have one thing in common. They have dedicated themselves and their personnel to making plungers work for them. The philosophy being it is good business to have a slightly larger work force to give plungers the attention required for maximum results. This rationale saves large additional capital expenditures on another production method that is much more expensive to operate.

The end result is dramatically reduced lifting costs and a resultant extension of economic limits.

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