INCREASING PRODUCTION USING MICROPROCESSORS AND TRACKING PLUNGER-LIFT VELOCITY

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ABSTRACT

The increasing recognition of Plunger-Lift as a viable method for producing many wells, has brought a number of changes to the technology involved. The importance of proper plunger-lift performance criteria (as reported in an earlier SPE paper) has been recognized and steps taken to incorporate this information into modern day control systems.

This paper discusses the usage of plunger velocity in establishing operating cycles for gas wells and for oil wells. When used in conjunction with state of the art electronic microprocessors, the results are increased production, extended economic limits, less down-time, and many others. This has been proven to be the case in both conventional and slim-hole wells.

Primary areas of discussion are:

1. Relativity of plunger velocity insofar as efficiency is concerned.
2. Standard approach historically taken to achieve maximum production.
3. New software design that automates cycle changes while increasing production and reducing both man hours and down time.
4. Test results and case histories.

Results, Observations and Conclusions:

Significant production increases have been realized in the vast majority of wells produced via this method. Modest increases were realized on the remainder of wells tested. Optimization, by using plunger travel velocity has proven to be highly successful. Increases in excess of 100% realized on many gas wells. Reducing down-time, saving man-hours, increasing production rates, handling line pressure changes and generally eliminating the most common problems associated with plunger-lift are the result of this approach.

Applications:

1. Gas well dewatering, even for marginal producers. For both conventional and slim-hole wells.
2. High GLR wells.

3. Wells with high or fluctuating sales line pressures.

INTRODUCTION

Plunger-Lift, which has been around for years, has been a real frustration for many operators. Wells which could have been helped were abandoned due to a combination of inefficient plungers, insufficient well data, poor field service, and control systems that were inaccurate and troublesome. Plunger-Lift was considered only as a last ditch effort by some operators and others wouldn't even consider it. Fortunately things have changed tremendously since those times, although some operators and suppliers continue to go about building and using equipment that is outdated, at best.

<u>Education</u> and the <u>introduction of microprocessors</u> have been the <u>real keys</u> to making plunger-lift the viable production technique it is today. As we evolved from "wind up" controllers to electronic controllers, much of the guess work was taken out of the "line-out" process. In addition to that, the accuracy and dependability of the new electronic controls was light years ahead of the manual wind-up clocks (which would fail at the most inopportune times, leaving the well loaded). With the manual clock method, the flow times and shut-in times were simply a guess at what the well could stand and was capable of doing. Electronics made it possible to control wells based on pressure, differential, flow-rate, plunger arrival, liquid levels, etc. This alone moved plungers into the realm of being a viable alternative to rod pumping, stop cocking, soaping, swabbing, siphon strings and in many cases, plugging and abandoning. Plungers were able to perform in situations which were previously impossible. <u>Operating more than one motor valve with a single controller, producing with a single-well compressor, and producing against high or fluctuating sales line pressures are but a few of the possibilities created by incorporating microprocessors into the system.</u>

RELATIVITY OF PLUNGER VELOCITY

In the 1980's a comprehensive plunger-lift study (see SPE 14344, Defining the Characteristics and Performance of Gas-Lift Plungers) was completed which gave us some real numbers on plunger efficiency. From this study it was learned that the type of seal of the plunger is very important. There was no "perfect plunger". There were different types of seals which were appropriate for different situations and well conditions. It was also learned that the efficiency of the seal had little to do with liquid fallback, but more with the gas slippage around the plunger. Gas slippage being gas that is lost (insofar as lifting horsepower is concerned) as it outruns the plunger on it's trip up the hole. The poorer the seal, the more gas slippage there was. The slower the tool traveled up the hole, the more gas slippage there was. In either case, gas slippage spells inefficiency from a plunger-lift standpoint.

It was apparent that getting the plunger to travel at an efficient speed was very important. Fast enough so that the gas slippage was minimized, yet not so fast that it was hard on equipment. Also, plungers traveling too fast mean that the system is not producing very efficiently. There is much more horsepower being expended than is necessary for the job to be done. It's similar to driving a vehicle with the tires spinning, you may be moving forward, but it is a waste of energy. In this case wasted energy that can be translated into greater production rates and a smoother operation.

STANDARD APPROACH

With this new information, it became easier to set up operating cycles for plunger-lift wells. It became a standard practice to operate a gas well using casing pressure to start the flow, and flow the well for a certain period of time or until a well reached a certain differential. Oil wells were cycled using pressure to initiate the cycle and shutting it in upon plunger arrival or after a brief afterflow period. The question was how to decide on the correct pressures, flow times, shut in times, afterflow times, differential, etc. The standard approach became to monitor the travel time of the plunger. Adjustments were made until the plunger travel speed fell into the correct range for what was thought to be the optimum efficiency. The controller was then set, with the idea that someone would monitor it's cycles periodically and make ongoing adjustments. This proved to be relatively inefficient. There were two problems with this scenario. One was that typically the ongoing adjustments weren't done regularly and as well conditions changed, the plunger would no longer be operating efficiently. Plus, it was necessary to set cycles which were so conservative that the well didn't load up completely when well conditions changed. Factors which effected the cycle efficiency were: fluctuating sales line pressures, plunger wear, well decline, inflow inconsistencies, paraffin in flow line, etc.

NEW SOFTWARE DESIGN

As microprocessors have helped most other industries, so have they made a difference in plunger-lift. Both hardware and software have been introduced to make the plunger-lift system simpler and easier than ever imagined.

In monitoring pressures, it was not possible to account for chokes, dump valves with small trim, compressors which could not move the gas quickly enough, and other fluctuations.
Even though the same pressure was available each cycle, the plunger velocity could vary. In many cases the variations were enough to create real problems in getting the plunger to surface on each cycle.

Keep in mind the fact that plunger seal efficiency and plunger velocity are the two key ingredients in successful plunger-lift. In the tests, the most efficient seals available were already being used, now the attempt was to track and control plunger velocity. It became obvious that tracking plunger velocity was already being used by field technicians. The plunger travel times were monitored for trouble shooting and line out work. An operating range was used to determine the necessary adjustments to both, flow and shut in cycles. The problem was that the field technicians could not remain on site 24 hours a day. It was necessary for changes to be made on the spot, as fluctuations or problems occurred. Plus, the changes which needed to be made needed to be subtle ones. It was learned previously that larger dramatic changes in the cycle could "shock" the well and yield unsatisfactory results. Small changes made for smoother transition and better results. With all this in mind, the goal was to create software that could do the same job as a technician. That would make the same decisions, and would be on the job 24 hours a day, watching each and every cycle. That would make changes if necessary, if not necessary it would simply monitor and store information.

The approach taken with this software was to monitor plunger velocity directly. To back away from recording pressures, flow rates and differentials meant that the problems and expense often encountered with switch gauges and transducers could be eliminated. By monitoring the plunger velocity, the results of pressure, differential and flow rate could be measured by using a simple MSO (Magnetic Shut Off) switch. This switch is a proximity switch located on the lubricator which signals the arrival of the plunger at the surface. The plunger velocity measurement technique assures the operator of outflow performance relative to all system conditions.

Velocity was measured by calculating the time it should take for the plunger to reach the surface, based on the depth of the well. In this way it became possible to set up a series of operating windows (See Figure 1).

The target was an operating window for ideal plunger performance. This was set up by establishing a "low time" and a "high time". The low time being the fastest the plunger should travel, the high time being the slowest the plunger should travel. This creates a "good window" and was the range the controller would be seeking. In addition to the good window, a fast and a slow window was established. This gave the controller an area to start making adjustments to get the plunger back into the good window. One other condition was entered, that being a "no arrival". A no arrival being a plunger that had not surfaced before the times in the slow window had expired.

Next, the changes to be made had to be established. The variables were flow time, afterflow time (afterflow being the flow after the plunger has arrived at the surface), and shut in time. If the plunger was coming up the hole too slowly, that meant the plunger did not have enough pressure for the size slug it was lifting. Either the slug size had to be made smaller or the pressure greater. For a plunger traveling too fast, the opposite was the case. If the plunger did not make it to the surface, certainly it needed much more pressure for it's next attempt.

The changes in settings are as follows
(See Figure 2):

For fast plunger arrival-Afterflow time is increased to bring in additional liquid, and shut in time is decreased for less casing pressure.

For slow plunger arrival-Afterflow time is decreased for a smaller slug size, and shut in time is increased for additional casing pressure.

For a no-plunger arrival-Afterflow time is decreased for a smaller slug size, and shut in time is increased for additional casing pressure.

An example follows:

When the control system and/or plunger lift system is installed, the well may be relatively strong. On the initial cycles, the plunger will often travel too fast. Each time the plunger does come up too fast (faster than the low time), the controller will add afterflow time and decrease shut in time. It will make these changes in whatever increments you select. These changes will continue to be made until the plunger starts arriving within the good window. For as long as the plunger continues to arrive within the good window, the controller makes no changes. It will record arrival times and compare them to the window, but no cycle changes are made.

As the well continues on it's normal decline, as the plunger starts to wear, if the sales line pressure increases, or any other changes occur that would cause the plunger to slow down, the controller will start making changes as soon as the plunger travel time moves into the slow window. For slow arrivals the afterflow time will be decreased. Usually the afterflow time will be decreased in larger increments than it was increased for fast arrivals. Also, the shut in time will be increased. It will be increased in larger increments than it was decreased for fast arrivals.

If, for some reason the plunger fails to surface before the end of the slow window expires, the controller will shut in the well. The shut in time will be increased and the afterflow time will be decreased.

It is not necessary to make changes to both the shut in and afterflow times,the software allows the option of an either/or operation. Normally, for optimum performance, both are used.

TEST RESULTS AND CASE HISTORIES

The results of this program has proven to be significant. It takes all of the guess work out of the line out process, plus allows the line out process to be done more consistently.
The number of man-hours normally required to line out a well is dramatically decreased. Changing well and/or surface conditions which would otherwise create problems are automatically accounted for and the appropriate adjustments made. Downtime is reduced and production rates are improved.

Another problem encountered and handled effectively was that of fluctuating sales line pressures. Normally sales line pressure increases creates problems for plunger-lift systems. The additional pressure the well has to overcome cancels out a portion of the casing pressure which lifts the plunger. A pressure sensor may be used to monitor sales line pressure. The controller can then either shut the well in until the line pressure drops, or change the cycles to account for the pressure change.

TEST WELLS

The initial test wells were gas wells in the DJ basin, and oil wells in East Texas (See Figures 3 and 4). On later installations, wells with packers and slim-hole wells were also successfully operated with increases in production. The slim-hole wells were in South Texas. In each area, several different producing formations were represented.

Each well tested was already being produced via plunger-lift before the new system was installed. In some cases the wells were previously felt to have been optimized, and in others the well was operating marginally. The test results reflect increases in production, not from installing a plunger-lift system, but from getting more efficiency out of an existing one.

The production rates reported were those reported by each producer, independently of one another.

CONCLUSION

Plunger-lift has come a long way from the 50's and 60's when it was a crude, inefficient and often troublesome method of producing a well. This new approach to producing marginal gas and oil wells has taken the guess work out and added a system of checks which insures much better results. It has made possible the efficient operation of plunger-lift systems by personnel who have little technical experience or who have little time available to devote to it. The various wells tested ranged from 1500 to 9600 ft. they were a combination of oil, gas, water and condensate. No significant problems were encountered. Identifying plunger-lift candidates properly before installing equipment is still essential, but, the spectrum of wells which are now appropriate for plunger-lift has broadened. As with most other types of oil and gas production, new technology coupled with experience has provided positive changes.

ACKNOWLEDGEMENTS

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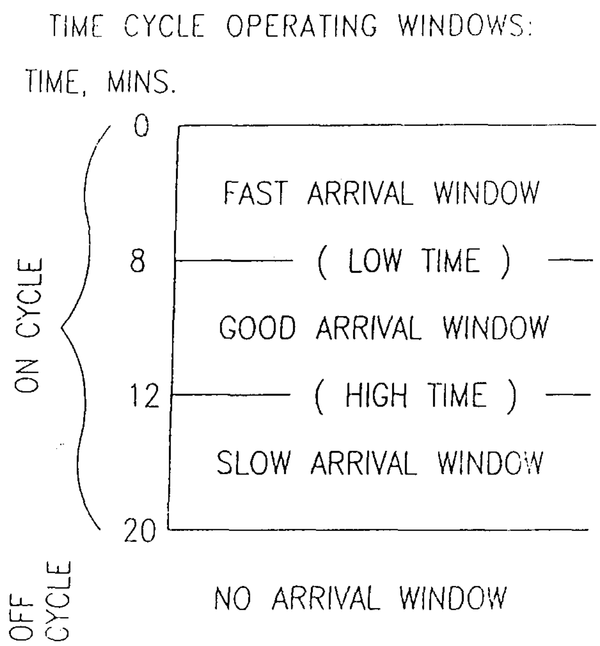

Figure 1

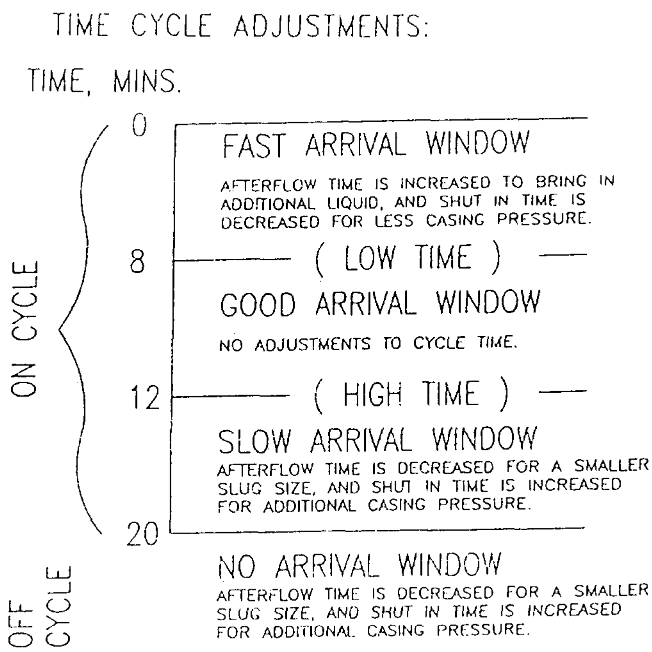

Figure 2

East Texas

Both of these wells were being operated with plungers and switchgage. Both experienced problems with fluctuating sales line pressure.

	PRIOR STATUS	PRESENT STATUS	CHANGE
1.	28 MCFD 2.2 BOPD	44 MCFD 2.6 BOPD	57% INCR. 18% INCR.
2.	85 MCFD 3 BPLD	165 MCFD 3 BPLD	94% INCR. NONE

N. E. COLORADO

All of the following wells were operating with

plunger lift and time cycle controllers prior to AUTO-CYCLE retrofit.

	PRIOR STATUS	PRESENT STATUS	CHANGE
1.	107 MCFD 0.5 BLPD	146 MCFD 0.61 BLPD	36% INCR. 22% INCR.
2.	32 MFCD 0.82 BLPD	65 MFCD 0.96 BLPD	103% INCR. 14% INCR.
3.	77 MCFD 1.3 BLPD	120 MCFD 1.6 BLPD	56% INCR. 23% INCR.
4.	39 MCFD 1.00 BLPD	72 MCFD 1.17 BLPD	85% INCR. 17% INCR.
5.	34 MCFD 0.75 BLPD	47 MCFD 1.10 BLPD	38% INCR. 47% INCR.

MEXICO

1.	108 MCFD Fluid production unknown.	170 MCFD	57% INCR.

Figure 3

South Texas

Both of these wells are slim hole completions operating with plungers with 2-7/8" tubing cemented in the hole.

	PRIOR STATUS	PRESENT STATUS	CHANGE
1.	120 MCFD 0.2 BWPD	280 MCFD 2 BWPD	133% INCR. 900% INCR.
2.	180 MCFD 4 BWPD	367 MCFD 4 BWPD	104% INCR. NONE
3.	220 MCFD	480 MCFD	218% INCR.
4.	310 MCFD	440 MCFD	41% INCR.

Figure 4