AUTOMATING PLUNGER LIFT MANAGEMENT

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Overview

Managing plunger lift operation with electronic control has the potential to radically improve the production of fluid loaded wells. For this improvement to be realized however, several factors must be taken into consideration, and the control system must meet certain minimum criteria.

For a control system to be successful it must address the needs of the operator, provide the control requirements specific to the physical constraints of the well, and incorporate a flexible and complete control system to empower the operator to manage the process of plunger lift with intelligent tools.

In The Beginning

Original plunger lift applications utilized mechanical or battery powered 'clocks' to regulate the production cycle of a well. Flow was interrupted after a user specified elapsed time to prevent fluid from accumulating in the well bore past the point where it could be 'lifted'. The well was then left off for a user specified elapsed time to allow adequate pressure to build up for fluid lift. This control scheme allowed the operator to coarsely 'tune' the system by varying the 'on-time' and 'off-time' to suit the physical parameters of the well.

Since the primary parameter being controlled was the elapsed time of the cycle, these clocks were only able to approximate the flow and pressure requirements of the well. Operators with wells which tended to 'log off' were forced to decrease the on-time to avoid having to swab the well. Operators connected to gathering systems with fluctuating line pressures were forced to extend the off-time to prevent failed plunger trips due to lack of adequate pressure energy. However, since these systems were much better economically than other available lift options and served operators well, they continue to enjoy considerable success as attested by the continuing sales of many clocked plunger systems.

Improving The System

It didn't take long for the industry to realize that time intermitted wells, by necessity, had to have extended off-times and shortened on-times. Many methods were utilized to 'optimize' the plunger cycle time.

The most notable examples of 'self adjusting' or 'self optimizing' controllers all include some method to measure the plunger cycle time or travel speed and adjust the on or off-times to compensate for deviations from some 'optimal' target. These system were a marked improvement to time only systems, but they still have one significant flaw. The plunger cycle time is not what we want to optimize. We want to optimize total production.

Fine tuning timers merely gets you more accurate timers, which at their best cannot predict or account for fluctuations in the formation, changes in flow characteristics, or pressures in the production and gathering system. There must be a better way yet.

A Better Way

The object of plunger lift is to mechanically assist the lifting of the fluid to the top of the well bore. The fluid must be lifted mechanically because the flowing velocity of the well is not high enough to entrain the fluid in the gas stream and produce the fluid in two or three phase flow. Therefore the object of our plunger lift controller should be to produce the well when the minimum requirements for successful lift are met, and shut the well in when the fluid in the well bore has reached a critical point.

The only way to accomplish this task across a wide range of field conditions and well dynamics is to utilize a control system which allows the operator the flexibility to choose the operational parameters which best identify these critical conditions in that particular well and to 'optimize' the total production volume by intermitting the well using these factors.

In addition, attempts to make this more complex control method 'self adjust' will fail to improve performance of the well because it is not feasible to 'teach' the controller the nuances of formation management, production management, and fluid lift. In this improved method we acknowledge that there is no replacement for a knowledgeable operator who can review past lift cycle data and make informed decisions about adjustments to the lift control system.

Application

Several factors can be used to determine the optimum point at which to flow and shut-in the well:

Casing Pressure—depending on the completion method and characteristics of the well, the surface casing pressure can be a very good indication of stored energy for lift, as well as fluid volume in the well bore.

Tubing Pressure—in most applications this pressure is most indicative of the ability to lift.

Line Pressure—a significant factor if this pressure varies.

Casing-Tubing Differential—one of the better indications of fluid build-up if flow data is not available.

Casing-Line Differential—if the completion method allows annulus gas to come up under the plunger this factor can indicate ability to lift and likewise can indicate fluid build up.

Tubing-Line Differential—Probably the most accurate method to determine lift potential, by controlling on the difference both formation fluctuations and line pressure variations are taken into account.

Orifice Differential or Flow Rate—the best predictor of fluid level and the most accurate factor to set for shut-in.

For example, a well on a timer operating 45 min. on and 2.0 hr. off, producing 125 MCF/D (for this example we will not go into detail on fluid volume or plunger equipment selection as this is outside the scope of this document). This well will cycle 8 times every 22 hr. The operator tells us that the well must be shut-in before orifice differential (DP) drops below 10 in H2O or the well will have to swabbed. He also has determined that the minimum tubing pressure required to bring the plunger to the surface is 235 psig. When the pressure data from the well is reviewed we find that the average shut-in DP (while on the 45 min. on-timer) is 14 in H2O, the average line pressure is 135 psig which tells us that we need 100 psig Tubing-Line Differential (TLDP) to bring the plunger up, yet the average start-up TLDP has been 137 psig.

We make the following application: set the new controller to shut-in the well at 10 in H2O DP and to start-up the well when the TLDP reaches 100 psig. When the well data is reviewed we find that the average on-time has increased to 50 min. while the average off-time has decreased to 1.5 hr. This translates to 8 cycles in 18 hr. and 40 min., or 22% more cycles and 11% more flow time per cycle. The bottom line is approximately 25% increase in production.

If the well had been on a 'self-adjusting' timer the results would be less dramatic, but would be positive. Since the well is now operating on pressure constraints alone the conditions seen by the plunger (volume of fluid to lift each cycle and energy available for lift) are consistent from cycle to cycle. Therefore, the plunger speed and elapsed arrival time will be consistent from cycle to cycle.

Fine Tuning

Field experience has demonstrated that without exception a properly configured control routine similar to that described above will always improve production over simple time or single pressure intermitters. Additionally, we have found that production is usually improved over 'self-adjusting ' routines for the reasons outlined above. But this is not where the story ends.

No control system can replace the knowledge and experience of field trained operators. By providing the operator with intelligent tools like the control system described, we can empower him to optimize the well using the real-time information provided. By alternately adjusting different parameters and trying different control variables it is possible in most circumstances to achieve production increases from 15% to 150%.

Additional Requirements

Everyday the requirements for data, control, and more accurate measurement become increasingly critical, it is worth considering the value of a unified approach to all these needs. While stand alone plunger controllers can do an adequate job of plunger control, they ignore the other areas of need, as well as the benefits to plunger control acquired through automation integration.

Flow measurement, custody transfer audit trail needs, flow control, emergency shut-in, and many other well head and production monitoring and control needs can be met utilizing a full function remote terminal unit (RTU) which incorporates intelligent control with monitoring and measurement. By providing communication between the RTU and a host software package, the operator can trend his production and pressure data, determine if the well needs to be visited, and make changes to the control parameters from the field office. This eliminates the need to visit the well several times a day or week to determine if the well is operating. By reducing wasted 'windshield' time the operator now has at his command the tools to evaluate production and make intelligent choices. As the operator becomes more efficient, he can dedicate more time to analyzing well data and adjusting his production variables to maximize production. And that, after all, is what this is all about.