A NEW CONTROL TECHNOLOGY FOR PROGRESSING CAVITY PUMPS

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ABSTRACT
This paper will cover a new control technology for progressing cavity pumps that was designed to meet the challenge of operating progressing cavity pumps. Extending the run life while producing all available fluids is the goal of all PCP operators. This paper will explain the technology and conclude by providing an example of a field study.

INTRODUCTION
Progressing cavity pumps have been used successfully in many industries. When applied in the oil field, the challenge has been in making sure the well does not pump off and cause damage to the stator. Several methods, from monitoring torque to manual fluid levels have been used. To date, none of these have been commercial successes across the board. With newer technology and proven algorithms, the SAM PCP controller has met this challenge.

WHY THE NEED FOR PROGRESSING CAVITY PUMP CONTROL
The first need is to reduce premature pump failure. The most common failure is due to stator damage. The most common stator failure is due to pump off. Pump off is defined as a lack of fluid entry into the pump, which causes a lack of lubrication to the stator resulting in extremely high temperatures being generated. This high temperature ultimately burns the elastomer in the pump. The rubber surface of the stator becomes hard, brittle and cracked. In severe circumstances the stator contour is completely torn up producing rubber at surface. There may be one or a combination of plugged pump intake, poor inflow, or production rates exceeding inflow. Many of these applications are gas wells, so the fluid level has to be low so that the low pressure gas wells will flow.

A second need is well optimization. We would like to reduce the field monitoring of fluid levels. Some problems associated with field monitoring of fluid levels are the following. Fluid levels are only an indication of how much fluid is over the pump at the time the fluid level is taken. There are a large number of misinterpreted fluid levels due to surface and rod noise and foam. Downhole anomalies such as high liner tops, bad dog legs, or other “non standard” configurations will result in false fluid levels. It is extremely time consuming to shoot fluid levels, adjust speed, allow the well to stabilize and shoot the fluid level again. This may not be soon enough to account for changes in inflow.

By optimizing the well, we not only get rid of the aforementioned field monitoring problems above, we also increase productivity for both the well and the field by increasing overall production, making a quick recovery from downtime, and having better time/cost management for operations.

CONCEPT -- A CONTROLLER DESIGNED TO MEET THE NEED
The control theory of the PCP controller is to optimize production of the well without causing pump off or torque issues. This type of control is achieved using Lufkin’s patented algorithm of monitoring flow rate and adjusting pump rpm via variable speed drive. The special hunting algorithm continuously looks for the most production. Any torque violations will override production control.

A description of the PCP control algorithm is as follows:
The PCP control algorithm requires the well to have the ability to vary the speed of the pump, monitor the torque of the rods, and measure the flow rate. The production algorithm controls the speed of the well based on the current production rate however if torque becomes an issue the torque algorithm will take over and control the speed of the pump based on the torque parameters that are preset. When the well is first started at the suggested start up speed, say 200 rpm, the initial well state is a settling period. This is the period of time that the production from the well is allowed to stabilize after any speed change. For our purpose we will use three minutes for the settling time.

After the three minute settling time the controller goes into sampling period. This is the period of time that the production from the well is measured and a flow rate is established. For our purpose we will also use three minutes for the sampling time. The flow rate that is established is total fluid in barrels per day for that period. The pump is then sped up between the hard set minimum speed change and the maximum allowable speed increase that is preset. The well is then placed back in the settling period again.

After the three minute settling period and the three minute sampling period, the algorithm looks at the flow rate and determines if it satisfies the minimum production requirement that was preset at commissioning. For this purpose we will use 3%. If the production increase is greater than 3% the speed of the pump will be increased a percentage of the previous production increase while remaining within the minimum and maximum speed change window and the hard set minimum speed change. This process is repeated until the minimum production requirement is not met, or the pump reaches the maximum speed allowed. At that time the pump is slowed down between the maximum and minimum speed decrease window that is preset at commissioning. See Figure 1.

After the well is ramped down in speed the settling and sampling periods are again observed and the production still needs to meet the minimum production requirement. There is a number of consecutive speed ramps allowed that is configured at commissioning before the challenging algorithm is implemented. For this purpose we will use four. After the well is ramped down in speed four consecutive times and the minimum production requirement is not met, the pump is sped up the hard set minimum speed change and the settling and sampling periods are again observed. If the minimum production requirement is met then the pump continues to be speed up and the production is tested. If the minimum production requirement is not met then the pump will be ramped down again and the process continues.

The concept is based on a user controller with a variable speed drive. The three inputs that are measured are flow rate calculated from a wedge meter, a positive displacement meter, or a turbine meter, rod torque, an input derived within the variable speed drive, and an rpm sensor measured the revolutions of the rod. See Figure 2.

FIELD STUDY RESULTS

Before implementing the SAM PCP controller, the pilot well for the field study had a colorful history with respect to failures. There were a recorded six pump failures over 18 months. In November 2004, the SAM PCP controller was installed. There have been no pump failures since installation to the present date. The fluid level has been consistently maintained at the pump. Before installation, the well was producing 49.85 BOPD and afterwards is now producing 57.54 BOPD, which equates to an increase of 7.69 BOPD (15.43%). An important remark is that the water cut is 90% because what is impressive is the overall fluid production increase. Total production went from 498.46 BFPD to 575.38 BFPD, a total increase of 76.92 BFPD.

Also included in our study were three other wells, each having light, medium, and heavy crude. After installing the SAM PCP controller, the production increases were measured. See Table 1. We also illustrate the differences in pumping speed, production rate, and fluid over the pump before and after the application of a SAM PCP controller. See Figure 3.

Concerning the light crude, at first the well was running at 200 rpm with a fluid level of 15 to 16 joints and production of 467.95 BFPD with a 94% water cut (28.08 BOPD). After employing the PCP controller, the motor is now running at an average speed of 280 rpm and maintaining 0 to 6 joints of fluid. Production increased to a mean of 605.32 BFPD (36.32 BPD), which is a 29.35% enhancement.

The medium crude well (which is a different well from the pilot well) exhibited similar results. This well, like the pilot well, had a 90% water cut. It started out running at 200 rpm with a fluid level of 5 to 6 joints and production of 339.64 BFPD (33.96 BOPD). The well is now running at an average speed of approx. 255 rpm and maintaining 0 to 1 joint of fluid. Production has increased to an average of 415.12 BFPD (41.51 BOPD), which equates to a 22.22% increase in production.

The heavy crude wells were a package of four different horizontal wells that are in a commercial water flood with production rates ranging from 188 to 1885 BFPD. The water cuts ranged from 25% -- 99%. On average, after installation, the wells increased oil production by 23.15 BOPD, which yielded a production increase of 4.9%.

CONCLUSIONS

It has been shown that there is a need for a PCP controller. First is the need to reduce premature failure of PC pumps. Another need is optimization. We would like to reduce the field monitoring of fluid levels. Meeting these needs is imperative because overall production will be increased for the well and for the entire field by increasing daily fluid production, recovering more quickly from downtime, and enhancing time and cost management for operations. The SAM PCP controller meets and exceeds the goals and expectations of increasing production and reducing failures.

Table 1
Field Test Results.

FLUID TYPE	WELL DEPTH, FT.	PRODUCTION INCREASE (BOPD)	PRODUCTION INCREASE (%)
(Pilot) Medium, 26 API	3281	7.69	15.43 %
Heavy, 17 API*	2133	2.32	14.94 %
Medium, 26 API	3283	7.55	22.22 %
Light, 30 API	3937	8.24	29.35 %

* 4 well package

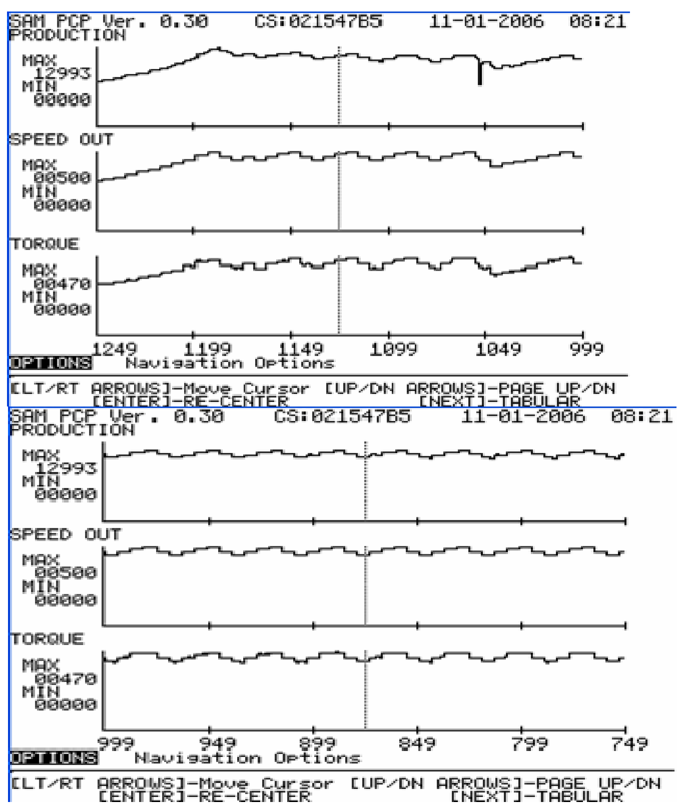

Figure 1 **-** On the left is the SAM Controller employing the hunting algorithm for optimal production, rpm, and torque. On the right is the SAM Controller showing stabilized production, rpm, and torque.

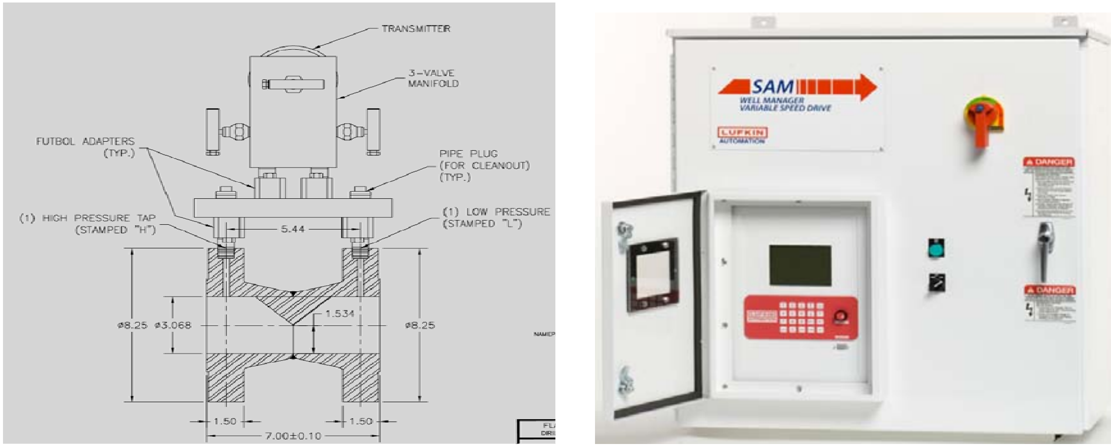

Figure 2 - On the left is the SAM VSD. On the right is a wedge meter used in calculating production.

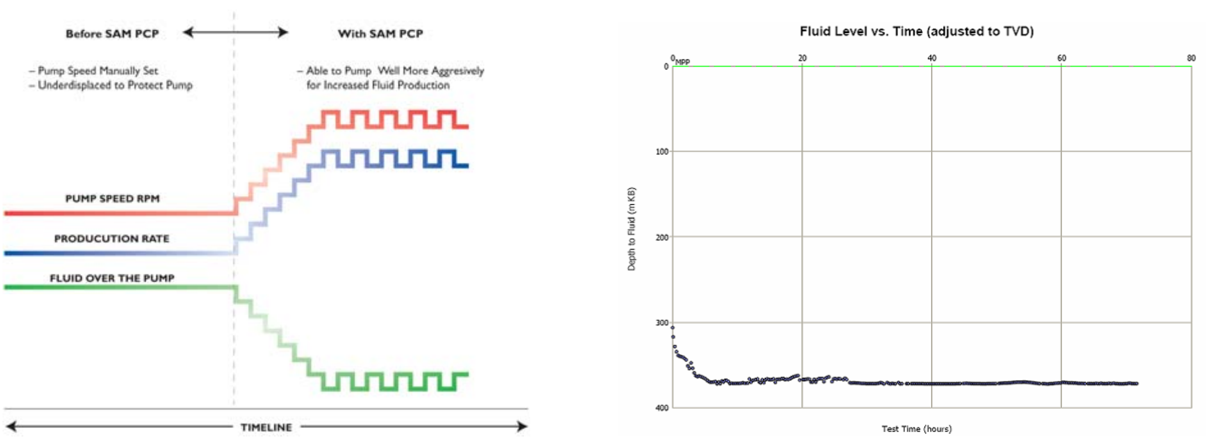

Figure 3 - On the left are plots of pumping speed, production rate, and fluid over the pump before and after the application of the SAM PCP control algorithm. On the right the fluid level is maintained at a constant level close to pump depth.