ADJUSTABLE SPEED DRIVES (ASD'S) FOR ARTIFICIAL LIFT SYSTEMS

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ABSTRACT

For years we have known that "Long and Slow" is considered a "Best Practice" for rod pumped wells and that continuous running is best for Electrical Submersible Pumps (ESP's). In a "Perfect World" we would have the ability to slow down or speed up a pumping unit or ESP to match fluid inflow and to vary the speed of the up and down stroke of the rod pump system to minimize rod buckling.

In reality, we design a rod pump system for 80 to 85% run time and minimize pump off pounding with a POC. Our ability to do this is often limited by pump unit or sheave size. Fluctuating production can result in high fluid levels and cycling of the artificial lift system. For ESP's we usually manually adjust the operating frequency based on monthly fluid shots.

The industry recently took a step toward that "Perfect World" with Adjustable Speed Drives (ASD's).

INTRODUCTION AND BACKGROUND

As the price of oil moved up into the $50 and $60 price range, workover rig availability became a bigger and bigger challenge. The reduced rig availability began to cause an increase in our backlog of wells in our routine well work queue which also resulted in an increase in our daily lost / down production. With $60 oil it was obvious that minimizing daily lost production was imperative if we wanted to remain a top quartile performer. Reducing the number and frequency of downhole failures was the only solution.

We took a hard look at our failures across the Mid Continent Business Unit and found that on a percentage basis most of the failures occurred in the Oil Area operations in wells on sucker rod or ESP pump. Looking at historic producing well failure rates for each of our field locations, we felt like we were doing a good job of preventing failures. In fact, in most cases, our fields were at or near the lowest failure rates they had ever experienced. Rod pumped failure rates ranged from 0.15 FPWPY (Failures / Well /Year) to 0.45 FPWPY. The average across the Permian Area was around 0.34 FPWPY. When we took a harder look, we found that approximately 51% or half of the failures occurred in 8 or 9% of the wells. Repeat failures (wells with 2 or more failures in 12 months) were our biggest cost in both lost production and rig time.

It was obvious that we must focus our efforts on eliminating repeat failures. The "Cause of Failure" shown in our failure database for most of the repeat failures could be sorted into basically two categories – chemical related and wear or over produced related. Examples of the chemical related failures were internal or external corrosion, bacteria, scale, and solids (iron sulfide). ASD's will not help these types of failures.

The cause of most of the repeat rod pump failures was listed as "Wear" and most of the wear failures occurred at or near the pump. The Root Cause of the wear could be tied back to polish rod velocity, pounding fluid, and simply over-producing the wells. We have operated with the philosophy of operating our pumping units "long and slow" for several years, however, because of the need to have pump capacity to pump the wells off after hot water or chemical treatments, declining production, fluctuating production in CO2 floods, etc. many wells cycle multiple times per day. The most desirable operation would be to have the well operate around the clock 24 hours per day while maintaining a fluid level just above pump off. Our current rod pump system design could not provide for this desirable operation.

Similarly, the causes of most of the repeat ESP failures, often listed as multiple causes of failure, could be tied back to a Root Cause of the ESP cycling. Motor or cable burns, solids in pump, asphaltene, etc., were some of the actual causes listed. Motor cycling causes power surges in the motor and cable on start ups stressing splices and equipment insulation systems. Also, during the down cycle solids fall back down on top of the pump, asphaltene precipitates in the pump and tubing, etc. These solids accumulate inside and on top of the pump, depending on down time, adding to the mechanical loading on the motor at start up and as a result reduce motor life. As in the rod pump case, the most desirable operation would be to have the well operate around the clock 24 hours a day while maintaining a fluid level just above pump off. Twenty-four hour operation would reduce insulation system stressing as well as keep motor mechanical loading to a minimum.

We were aware that Variable Frequency Drives (VFD's), now most commonly referred to as Adjustable Speed Drives (ASD's), for pumping units had been around for many years. They had not been very successful in the past but we decided to take another look at them. What we found is that there are several manufacturers of ASD's for pumping units on the market now. Just to be clear – these are controllers that *automatically adjust the frequency and voltage* to meet operating conditions, not controllers that an operator has to manually adjust the drive parameters based on fluid level, etc. Some of the manufacturers are Lufkin, Well 2 Web, Unico, and Varco to mention only a few. The complexity of operation, setup, and price of the units run the complete gamut from low to high. This paper will not mention any specific manufacturer's drive, but will discuss the benefits of using ASD's on producing wells in general terms.

CASE STUDIES

Wharton Unit Well No 105 (Rotaflex)

The Wharton Unit Well No 105 is a Glorietta well pumping from approximately 5,800'. It had a Rotaflex Pumping Unit with a 2-3/4" big bore pump. The well produced 20 BOPD and 700 BWPD operating at 4.3 strokes per minute (SPM). The well had experienced 4 tubing and pump failures in 9 months at a cost of $73,000 plus the value of the lost production.

In August of 2004 an ASD was installed and set to vary the unit speed from 3.3 SPM on the down stroke to 5.3 SPM on the up stroke. The speed transition from 5.3 to 3.3 and back to 5.3 SPM was set to occur before the top of the up stroke and after the transition from the down stroke to the up stroke. In other words, the directional transitions occur at the slower speed of 3.3 SPM. As of February 1, 2006 (17+ months) there have not been any additional failures on the well.

Gin Well No. 1103 (Conventional)

The Gin 1103 is a Spraberry well pumping from approximately 8,100'. It has a 640 Conventional Pumping Unit. It produces 120 BOPD and 200 BWPD operating at 8.6 SPM. The well experienced 6 sucker rod and pump failures over a 15 month period at a cost of $93,000 plus the value of the lost production. The well was considered to be a candidate for a Rotaflex Pumping Unit with an ASD (based on the success of the Wharton 105 previously discussed). The joint interest agreement required partner approval before we could proceed. It was decided to go ahead and install the ASD and wait on partner approval to install the Rotaflex.

On February 23, 2005 the ASD was installed. As of February 1, 2006 (11 month) the well has not experienced a failure. The Rotaflex was utilized on another well.

Carney Well No. 7-35 (ESP)

The Carney 7-35 is a Weaver well pumping from approximately 5,800'. The ESP was installed on the well February 10, 2005. At the time production averaged 30 BOPD, 400 BWPD, and 150 MCFPD, By May, 2005, declining water and increasing gas production caused the well to cycle as much as 11 times per day. This was a concern because field history shows ESP's that cycle have a much shorter life than those that run continuously. They also have more problems from asphaltene deposition and solids falling back. The cost of an ESP failure averages about $42,000 plus the value of lost production.

On June 6, 2005 an ASD was installed. As of February 1, 2006, the ASD varies the speed of the ESP to match the production that constantly varies due to CO2 WAG cycles. The well operates continuously without cycling and production averages 30 - 35 BOPD, 81 - 400 BWPD and 400 – 1000 MCFGPD. Fluid level above the pump is maintained at approximately 150' as verified by fluid level shots and the internal POC in the ASD. .

APPLICATIONS

As discussed in the background above, we had identified our target wells as those wells experiencing repeat failures. Below is a listing of the various applications we have actually utilized ASD's on:

Conventional and Mark II Rod Pumping Units

- Slow down unit – Operate 24 hours per day to eliminate cycles and maintain fluid level as low as possible to maximize fluid in-flow without introducing excessive rod pound..
- Vary the up and down stroke speed - Slow the down stroke and speed up the up stroke to reduce rod buckling and pounding.
- New well stabilization – Match fluid decline without cycling to help move solids, reduce solids fall back, and minimize paraffin and asphaltene deposition
- Eliminate the purchase of larger lift equipment- Loads are reduced by minimizing speed and cycles.
- Pump Off Control - Provide pump off control on wells without POC's based on motor torque.
- To convert single phase power to three phase to utilize existing single phase power lines.

Rotaflex Pumping Units

- Vary up and down stroke speed - Slow the down stroke and speed the up stroke to reduce rod buckling above pump
- Speed the down stroke and slow the up stroke to minimize side loading and wear in a near surface dogleg
- Smooth transition cycle - Slow down the unit during up stroke / down stroke directional transition to minimize equipment loading

Electrical Submersible Pumps (ESP'S)

- Eliminate cycles - Slow down ESP to match in-flow especially in CO2 fields.
- Reduce Solids Fall Back by eliminating the down cycles and keeping the fluid moving.
- Reduce paraffin and asphaltene deposition by eliminating the down cycles where fluids cool down in the wellbore.

CONCLUSIONS

Adjustable Speed Drives have a definite benefit in the oilfield. When placed in the correct application the ASD can:

- Reduce Failures – Failures, both surface and downhole, are reduced by eliminating fluid pound, reducing rod buckling, reducing or eliminating cycling (applies to conventional, Rotaflex, and ESP's), smoothing the up stroke / down stroke transition, and reduced motor temperature as verified by infrared survey. In new wells ASD's can prevent the solids fall back that occurs during "well clean-up" as production declines and the well begins to cycle
- Optimize Production – Production in-flow is maximized by continuously maintaining the fluid level in the annulus as low as possible rather than letting the fluid level build during down cycles. In new wells the drive can slow the Unit to match the declining production.
- Reduce Equipment Changes – By reducing the loads on equipment the equipment will run longer and as production increases it can be produced without increasing equipment size.
- Reduce Operating Expenses – Fewer failures translate into lower operating costs.

- Reduce Downtime – Fewer failures translate into lower downtime simply by keeping wells producing longer and by being able to get on the well faster when it does fail.

- Fast Payout – Most of our installations pay out in a matter of weeks based on reduced lost production alone.

POTENTIAL BENEFITS NOT YET VERIFIED

There are several potential benefits that have not been verified at the time this paper was written.

- Power Savings – Currently under test.

- Optimize Paraffin Treatment Schedules – By eliminating the down time and keeping the fluid moving, we believe we can extend our paraffin treatment intervals. We may also be able to see an increase in load with the ASD as paraffin forms and treat based on need rather than time interval.

- Efficiency Increases – Nema B motor vs. “high slip” Nema D Motor

- Power Factor of .97

FINAL COMMENTS

We currently have approximately 110 ASD’s in service in the Mid Continent Business Unit. ASD’s are not a cure-all for poor designs, lack of optimization, or lack of artificial lift knowledge. They are a tool requiring significant capital investment that can help maximize the benefits of proper design, POC’s, and total system optimization if that alone does not deliver acceptable run times.