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The Direct-Drive Variable-Speed Drive Head for PCPs Saves Big Bucks

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Abstract

Implementing a new configuration for the drive head for progressive cavity pumps can solve many operational problems and lower operational costs. Capable of handling high sand loads keeps the pumps on and reduces downtime. Simplicity of design makes them easier to operate, more reliable, and less costly to maintain. Simple design of inline motor to a gear reducer coupled to the polish rod eliminates the problems and dangers associated with conventional belt and pulley configurations. When coupled with a power inverter the drive head speed can be easily controlled over a wide range of speed and quickly adjusted for pump saving control.

Introduction

Progressive cavity pumps (PCP) are now used throughout the oilfield for lifting all types of fluid from water, light oil, to heavy viscous and sediment laden fluids. The original drive head configuration was a belt and pulley system to rotate the rods and pump in the well. Fluid enters the pump and the rotation of the rotor in the stator sends the fluid to the surface. Changing downhole reservoir fluid conditions can change the torque necessary to turn the rotor. When this happens, drive belts burn on the pulleys and the system fails. In Parrylands Field the producing Forest Formation is unconsolidated and periodically gives up slugs of sand. The sand slugs increase friction in the pump and increase the necessary torque to turn the pump. Utilization of a direct drive system has meet the demand of the increased torque from a sand slug, pumping it to the surface and preventing failure.

PCP Oilfield use

Progressive cavity pump key components are the rotor and stator. The rotor is an external helix typically machined from high-strength steel. The stator is an internal helix typically molded of tough, abrasion-resistant elastomer, permanently bonded within a steel tube. The stator always has one more helix than the rotor to facilitate the progressing cavity pumping action. As the rotor turns within the stator, cavities are formed which progress from the suction to the discharge end of the pump, conveying the process fluid. The continuous seal line between the rotor and the stator helices keeps the fluid moving steadily at a fixed flow rate proportional to the pump's rotational speed.

Initial pump designs were for clean fluids. As needed, variations in stator materials, soft to hard, low temperature to high temperature, and close fit to loose fit of the rotor in the stator have been developed to handle various types of fluid and materials. Field experience has shown that the PCP is capable of moving fluid with up to 50% sand with the proper rotor stator design.. With each slug of sand, the torque on the pump and drive motor can increase significantly as measured by the static amp load. Normal load on a 5 hp motor is less than 3 amps with 50% sand laden fluid it can exceed 6 amps.

Investigation and Analysis

The conventional drive system is configured with a 1750 rpm electric motor, pulleys and belts to reduce the speed at the drive string to approximately 100 rpm for the downhole PCP. Increased torque conditions downhole are immediately transferred to the surface pulleys and belts. If the belts are not set right they slip, burn, then break.

The main challenges faced were keeping belts on the pulleys of the drive head system so that the unit(s) operated on a continuous basis. Further, reservoir conditions required us to frequently vary the speed of the drive head in response to fluid level dynamics which proved difficult.

Initial work on these challenges began with the analysis of the weakest link; the belts and pulleys in the drive head assembly that rotate the rod string to actuate a progressive cavity pump (PCP).

Reasons for belt failure resulting in system failure were determined to be:

- Slippage due to the belts stretching over time.

- Slippage and wear due to torque variances as solids enter the fluid stream.

- Slippage caused by heavy rains which reduce the friction between belt and pulley.

- Wear caused by misaligned pulleys, which ultimately results in belts burning off the pulleys which in turn caused the pumps to stop rotating.

Successfully implementing a program to service the belts and overcome the reasons for failure proved to be impossible. The drive head belts were monitored on a daily basis, and if they appeared to be slack or slipping, adjustments to the housing section to take up stretch was done immediately. The process of tightening belts would take five minutes (once on site). During heavy rains, field men would be redeployed to the well sites to inspect for slippage. If slippage was seen, they would tighten the belts in an effort to prevent them from burning off.

Belt Failure

Replacement of a belt required a roustabout crew of 2 to remove belt guards and loosen all elements of the pulley system to replace the belt(s). Having loosened all the alignment bolts extra time is necessary to realign the motor and pulleys to prevent wear on the new belts. This process generally took the two men 15 minutes (once on site). Cost of a belt US$55 + dispatching crew US$85 resulting in a total repair cost $140. Additional pulleys and belts did not reduce slippage and increased the belt replacement cost.

Most of the belt slippages when observed during daylight hours were corrected. However at night the belts burned off before morning. A rotating motor pulley spinning at 1750 rpm will render a belt inoperative within a few short minutes. Even scheduled day light spot checks often missed situations where a belt was about to start slipping.

Problems compound when the PCP stops turning. Each time this happens, there is a good chance the rotor will become stuck. The longer a pump is stationary the longer solids in the fluid have a chance to settle around the pump rotor. Settling solids onto the rotor section increase the chance of sticking the pump and rods in the tubing. Once a pump becomes stuck, additional cost is incurred to clean flush the pump, or worse case pull the tubing and stripping out the rods. To do this, a workover rig and a high-pressure pump are needed. (Cost US$270/hr for the rig for 10 hours).

Variable Speed

Pumping oil from a well requires sizing the pump to match fluid entry and varying the pump rate to match changing rates. As the rate of fluid entry into the well bore varies, the pump rate (rpm) must also be adjusted to match the entry in order to maximize production and prevent the pump from dry pumping rendering it inoperative. The process of matching pump rate to fluid entry over the life of the well requires frequent fluid level measurements and adjustments to pump speed. To manage this problem, belt and pulley driven systems have incorporated the following solutions.

Install an adjustable pulley mechanism, which varies the depth of the groove and thus varying the size of the pulley to vary RPM. This system requires a roustabout crew to adjust the pulley mechanism and realign the drive head. (Cost $75/hr 3 hr minimum to go out and adjustment drive head = Total $225).

Change out pulley sizes and realign unit to slow down or speed up the pump when needed. (Cost of pulley $250 plus labor $250 = Total cost $500+/-).

Replace standard 1725 rpm electric motor with a more costly 800 rpm motor. (Cost $1350 for a slower speed motor, i.e., 3 times the cost of 1725 rpm).

Replace the downhole pump with a larger or smaller capacity pump as needed. (Cost of new pump).

All options are costly and time consuming.

Solution Designs

The Direct-Drive pumping unit uses a simple in-line approach.
A 5 hp 1750 RPM electric motor is bolted directly to an in-line double reduction helical gear drive. The gear drive has four foot mounts which are bolted to a pivoting back plate assembly. When the pivoting back plate is locked into the vertical or in-line position, the output shaft of the gear drive is positioned directly over the polish rod. When the pivoting back is unlocked and tilted onto the back plate rest, the gear reducer and electric motor are out of the way giving full access to the rod string to be worked as needed without removing any portion of the drive head.

The output shaft of the double reduction helical gear drive is threaded to a flexible shaft coupling. This compensates for any potential misalignment, simplifies installation and provides a safety feature for the gear drive. In the event the rod clamp slips the flex coupling will disengage preventing the weight of the rod string from being carried by the gear box.

Once the pump rotor is spaced and the back plate is pivoted to its in-line position, the electric motor and gear drive assembly is lowered into place by sliding along its track until the flexible shaft coupling joins together. The bolts on the gear drive foot mounts are tightened to the back plate to provide support. At this point the output shaft of the gear drive is connected directly onto and in-line with a polish rod and rod string which is used to turn the pcp pump at a predetermined set speed; i.e. if a 10:1 internal gear ratio assembly is used in conjunction with a 1750 rpm motor then the output shaft speed will be 175 rpm.

Vertical alignment and horizontal positioning are the same each time due to design of the back plate, and pivoting hinge assembly. Once the back plate gear housing support is moved into the up position for operation, it is locked into place by a bolt.

A digital phase inverter / controller is used to enable the operator to instantly slow the motor down to a minimum of 50% output without causing damage to the motor. With a push of a button the operator can reduce the pump rate quickly to prevent burning up the downhole pump. With the belt and pulley system it would be necessary to dismantle the entire drive head to change the pulleys. If the wrong ratio is chosen then this will be done again until right.

Rod torque stored in the rod string is another problem when the surface drive head stops. The resulting backspin of the surface drivehead can be very sudden, very rapid and very dangerous. The backspin in this system is slowed by the double reduction helical gear drive. However, to address higher back spin rates associated with lower gear ratios, a dynamic electronic braking system can be added to the electronic digital controller.

Backspin velocity can reach 10 times normal operating speeds. The event of backspin is well documented and can cause serious damage and or injury. A rapid backspin can cause the tubing to back off requiring a workover to fish the parted tubing. (Cost = tool rental plus a rig for a day $1000 +/-).

Rapid backspin is hard on the drive head components

Rapid backspin can cause personal injury. (Cost priceless).

The use of the gear reducer / torque converter acts as a brake reducing the backspin velocity through the resistance generated by the torque converter gear reducer. During shut down, the unit will backspin but because the energy passes through a 10:1 gear reducer / torque converter the spin is slowed to a rate within the working range of the drive head.

Several unit shut downs were observed during the development and testing period. The resulting backspin was much slower than the belt and pulley system reducing the associated hazard and cost. The production crew has reported no tubing back offs resulting from backspin associated with the Direct Drive. However, several have occurred on belt driven units during power outages.

The direct drive pumping unit includes a combination stuffing box / pumping tee assembly at the bottom of the drive head housing. By machining all components into one piece, the need for additional nipples, flanges, tees, and or separate devices below the drive head section was eliminated. This also lowered the in-line drive head profile and provided the operator with a means of preventing the drive head from spinning, if it became loose from the mounting support.

Other elements associated with this particular drive head design are common in the industry. The polish rod clamp keeps the rod string from slipping into the well and also serves as an interlocking element to a load bearing shaft. Internal load bearings support the rod string and enable the device to rotate the rod string and PCP. A unique bolt on load bearing section with a 50,000 lb dynamic working load capacity was designed to make field replacement possible. An opening along the circular drive head housing enables access to the stuffing box section. A hammer union connection was used to simplify the drive head attachment to the well head.

Development Testing

The prototype drive head was completed on July 1, 2003 and installed it on E-237 on July 11th. This first unit pumped the well for 30 days before weak elements in the torque transfer to the rod string and shaft alignment were identified. After these issues were solved, the prototype operated trouble free during the 11-month test period. The production graph Figure 2 shows consistent trouble free operation July 2003 to June 2004.

Operational Cost Analysis

A cost and function comparison of one of the best producing wells on a belt & pulley system E-185, the prototype system installed on E-237, and the E-182 a problematic well clearly illustrates the efficiency of the design ,Table 1. The test period for these wells was from July 1, 2003 through May 31, 2004. As of this report, a total of 24 belt and pulley drive units and 24 Direct Drive units are in use in the field.

During the test period, the Direct Drive Head operated 97.84% of the time. The E-237 unit was down only during power outages and for a design change to enhance the shaft connection. It never required a pump change or work over rig to service the well.

The E-185, belt and pulley drive head, operated 71.30% of the time. It required additional expense of US$4067 in repairs to keep the well pumping due to the failure of belts and stuck pumps.

In the problematic E-182 the belt and pulley system was replaced with a Direct Drive unit in the last four months of the test period. In the subsequent four months of operation, the Direct Drive unit produced four times more oil on a consistent basis, through high torque conditions, as higher levels of produced sand and oil were pumped out of the well. The downhole pump was placed below the perforations and the direct drive was able to pump the sand out with oil without stopping. Over time, the well cleaned up (percentage of basic sediment / sand diminished) and the well continues to pump consistently trouble free.

Conclusion

The Direct Drive motor/gear reducer combination has solved the sand slug problems with continuous torque and pump power.

The use of the digital frequency converter to vary the speed of the electric motor gave us "instant" push bottom control over the speed of the unit. If a fluid level reading showed the need to slow the pump down, we could slow the unit down within seconds without calling out a roustabout crew.

The operator can now make instant speed adjustments to match changes in fluid levels. This eliminated the need for a roustabout crew to make the adjustments needed on a belt and pulley system. In addition, longer pump life is being observed and fewer pumps are failing because they are being operated within the fluid entry range.. This technology also enabled us to increase the operational rpm range of the drive head and thus extend the PCP (the pumps) output range. The operator now has greater flexibility and margin for safety.

All of the belt driven drive heads are being replaced with the direct drive head as they fail.

Table 1

WELL	E-185 Belt & Pulley	Cost Factor	E-237 Direct Drive	Cost Factor
Days of Operation:	236/324 (71.30%)		317/324 (97.84%)	
Lost Days Due to Belts	30		0	
Avg. Daily Production Bbls	6.5		7.7	
Cum Test Production Bbls	1515		2448	
Lost Test Production	195	$3900	0	$0
Belt Replacements	4	$510	0	$0
Workover Rig Days	3	$3000	0	$0
Pump Speed Adjustments	3	$650	3	$0
TOTAL COST		$8060		$0
WELL	**E-182 Belt & Pulley**		**E-182 Direct Drive**	
Days Of Operation	210		120	
Cum Test Production Bbls	287		1244	
Belt Replacements	3	$385	0	$0
Workover Rig Days	3	$3000	0	$0
TOTAL COST		$3385		$0

Figure 1