A COMPARISON OF VARIABLE SPEED DRIVES AND PUMP-OFF CONTROLLERS IN AN UNCONVENTIONAL RESERVOIR

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ABSTRACT
The Variable Speed Drive (VSD) is a popular rod lift control system for operators striving to maximize oil production. While the flexibility of VSD systems is clear, initial results from the Eagle Ford challenge the notion that controlling rod lift systems with VSDs will result in increased production when compared to the performance of the modern, stand-alone Pump-Off Controller (POC). With their high capital and maintenance costs, VSDs may become difficult to justify for application on tight shales where brief disruptions in production have less of an impact on reservoir inflow. This review of VSD and POC advantages, disadvantages, and performance data will help operators in unconventional reservoirs make an informed decision between rod lift control systems.

INTRODUCTION

Rod lift is one of the oldest and most common artificial lift systems used in the oilfield. Rod lift control systems have developed rapidly over the past several decades in an effort to achieve low formation backpressures while preventing fluid pound associated with over pumping wells.[1] Early methods to prevent the detrimental effects of excessive fluid pound – manually starting and stopping units, clock timers, and percentage timers – have been replaced by modern rod lift control systems designed to closely match lift capacity to reservoir yield.[2] Today, there are two primary options for operators: the stand-alone Pump-off Controller (POC) and the Variable Speed Drive (VSD).

The POC

A POC monitors surface polished rod loads and positions and can shut down the pumping unit when the system detects a pumped-off condition or other pump malfunction. The system is able to match lift capacity to reservoir inflow by stopping the unit when pumped-off and resuming pumping after a pre-set period of downtime.[2] Because the motor speed is set by the available fixed current source, a pumping unit controlled by POC is only able to operate at a set speed, measured in strokes per minute (SPM). The advent of inexpensive microprocessors in the 1980s gave rise to POCs with the storage and processing power to become true well management tools that can be remotely monitored and operated when connected to SCADA systems. Soft starters can be added to POC systems to eliminate high instantaneous current demands on electrical distribution systems. In addition to eliminating fluid pound, POCs have demonstrated their ability to reduce power consumption, reduce surface and downhole maintenance costs, and provide modest increases in production.[3]

The VSD

In a VSD system, a POC is paired with a variable frequency drive (VFD). The VFD alters the speed of the pumping unit motor, and thus the pumping unit and downhole pump, to match the reservoir inflow. The result is continuous pumping with minimal intervention by the operator. The POC component provides a secondary pump-off feature to shut down the pump if the slowest set speed still outpaces reservoir inflow.

The claimed advantages of VSDs over stand-alone POC systems are well published and in most cases supported. With continuous pumping at varying speeds, the VSD controlled pump can more accurately match the inflow of the reservoir as compared to a stand-alone POC unit. The VSD system is extremely flexible and can adapt to changing conditions without the need for sheave changes or operator intervention. This flexibility can be particularly attractive in an immature field like the Eagle Ford, where field personnel training is in its early stages and supervisors and engineers tend to be more focused on building infrastructure and bringing new wells online than monitoring base production. Continuous operation can prevent pump damage caused by sand or solids settling on downhole pumps during frequent shutdowns. Other advantages include the ability to slow down automatically to prevent reaching mechanical limits or difficult pumping applications and the ability to use more efficient NEMA B motors.[3]

The disadvantages of VSD systems primarily revolve around the theme of increased operating cost. Due to their increased complexity, VSD systems cost more to purchase, install, and maintain than compared to a stand-alone POC. With components that convert between alternating and direct current while dissipating regenerated power, expensive repairs can become an unpleasant surprise for the cost conscious operator. Increased system complexity also requires intensive training to help field personnel learn to use the equipment to its full potential. An operator should not overlook the criticality of field personnel cooperation and acceptance when deploying new technologies and equipment.[2] The downside of continuous operation is increased power draw and decreased downhole pump efficiency as slippage volume increases as a fraction of pump displacement at low speeds. As a result, the outcome of slow, continuous pumping is often more strokes per day for the same production volume. In addition, low pump speeds are often limited by electric motor cooling needs and lubrication requirements of pumping unit gearboxes.

A recent study demonstrated an operator's extensive use of VSDs to manage a large number of wells spread throughout the Cooper Basin of central Australia. Through a remote control and monitoring program, the operator reduced operating cost by 75%, downtime by 3%, and increased oil production by 18-30%. However, it should be noted that these impressive gains were not achieved by the use of VSDs alone, but by shifting from 0% well automation to 90% automation.[4] It is evident that a robust SCADA infrastructure and monitoring program are critical to an operator's ability to realize all of the potential gains that rod lift control systems can deliver.[5,6]

Selection of Rod Lift Control System in an Unconventional Reservoir

Both types of rod lift control systems have proved particularly useful on horizontal wells in unconventional reservoirs that are challenged by rapid decline rates, long, deep laterals, and production characterized by non-steady state, two-phase slug flow.[7,8] However, while a high permeability, low pressure reservoir may benefit from the aggressive continuous pumping that a VSD can deliver, the benefits of continuous pumping may not be worth the increased capital and operational costs in a low permeability reservoir. In an unconventional, low permeability, average pressure reservoir like the Eagle Ford, the advantages of slow, continuous operation of a pump are negated by increased slippage and gas interference due to constant drawdown.[9] Constant runtime increases wear and tear on downhole equipment as well as electricity costs.[10] While the VSD provides an operator with increased flexibility, it is still unclear that VSDs can deliver increased production when compared to stand-alone POCs. To this end, sixteen Eagle Ford wells were examined to further compare production rates delivered by a VSD versus POC.

ANALYSIS

The focus of this study is a group of sixteen Eagle Ford wells on rod lift with three-phase motors that were initially controlled by VSD systems powered by natural gas generators. When grid power was introduced to the area, these wells were converted to POC systems with soft starters. The wells were typically shut in for two days to complete the conversion, but in some cases took as little as one day or as long as seven days. The VSDs were typically set with maximum and minimum speeds at 5 and 3 SPM respectively. It was standard to have primary pump fillage set at 70% and secondary pump off set at 50% with 60 minutes of downtime. Once transitioned to POC, the units ran at speeds ranging from 4.7 to 5.2 SPM depending on pumping unit design and sheave sizes. Similar to the VSDs, the POC pump-offs were typically set at 70% with 60 minutes of downtime. The production data from before and after the control system exchange was examined. Raw production data from one month prior to one month after was examined first. Next, due to uncontrollable downtime caused by disruptions in electricity supply (grid or generator), midstream problems, offset hydraulic fracturing jobs, etc., a simple decline curve analysis was used to compare production performance prior to and after the swap. Percentage increase or decrease in oil and gas production for both the raw data and simple decline curve analyses were compared. The failure histories for the set of wells was also examined.

Results and Interpretation

The analysis of raw data revealed that 10 of 16 wells increased in oil production after transitioning from a VSD to a stand-alone POC. On average, the set had a 26% decrease in gas production, 18% increase in oil production, and 43% increase in oil and water combined (see Figure 1). When using a simple decline curve analysis to exclude the impact of outside factors, 14 of the 16 wells showed an increase in oil production with an average 7% decrease in gas production, 23% increase in oil production, and 44% increase in total liquid production (see Figure 2). A significant difference in failure rates between units controlled with VSDs versus POCs could not be detected.

The Eagle Ford is characterized by low permeability with an average pressure gradient ranging from 0.5-0.8 psi/ft.[11] As a result, back pressure at the wellbore builds slowly during shut in periods and represents a small percentage of the total reservoir pressure. This type of reservoir has higher gas saturations near the wellbore that increase the compressibility of the system. These characteristics greatly diminish the benefits of aggressive continuous running strategies and challenge the economics of VSDs when compared to stand-alone POCs.

CONCLUSION AND RECOMMENDATIONS

Continuous drawdown in a low permeability reservoir leads to increased gas interference and slippage which can be counterproductive for oil production. From the results of the analysis, switching from a VSD to a POC had a positive impact on oil production. While the flexibility provided by VSD systems may fit into the operating strategies of some E&P companies, VSD systems should not be counted on to increase production when compared to stand-alone POC systems. Ultimately, production gains are achieved through linking rod lift control systems to a robust SCADA infrastructure and monitoring system. Furthermore, a monitoring and optimization system that focuses the combined efforts of technicians, supervisors, and engineers will prevent rod lift failures and maximize pump runtimes.

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Table 1: Average production volumes before and after change from VSD to stand-alone POC rod lift control systems.

	Before (VSD)			After (Stand-Alone POC)			% Change		
	Gas (Mcf/d)	Oil (bpd)	Water (bpd)	Gas (Mcf)	Oil (bbl)	Water (bbl)	Gas	Oil	Total Liquid
Raw Data, +/- One Month	68	47	8	50	55	24	-26%	18%	43%
Simple Decline Curve Analysis	84	56	9	78	68	25	-7%	23%	44%

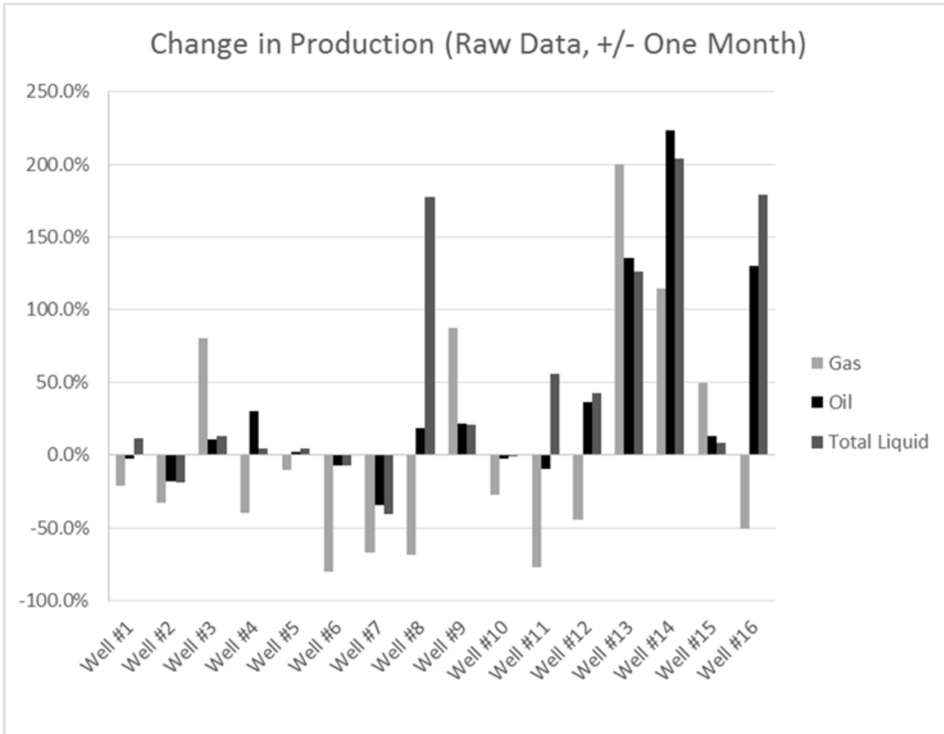

Figure 1: Comparison of production after transition from VSD to POC, using production data +/- 1 month.

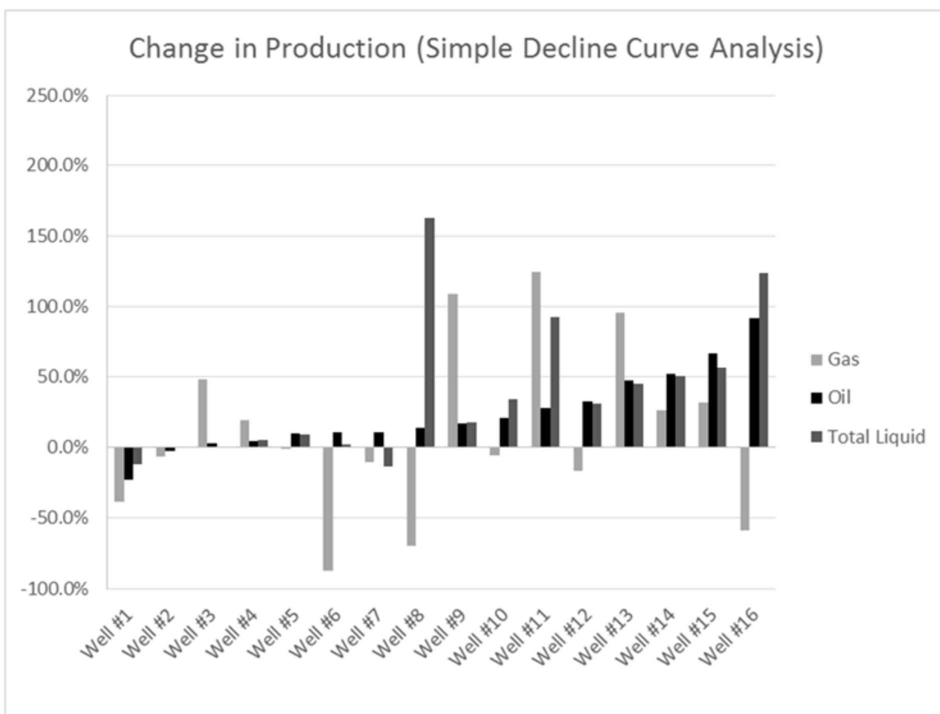

Figure 2: Comparison of production after transition from VSD to POC using simple decline curve analysis.