STRIPPER WELL PUMPING STRATEGIES

Carter D. Copeland Bruce Martin and Brian Williams
Owl Energy Services, Ltd

ABSTRACT

Technology has developed to integrate pump off control with variable speed drives to capture the secondary benefits of reducing equipment loads and increasing production through continuous drawdown. This paper will discuss the reservoir engineering factors that may limit the effectiveness of this technology advancement. In addition, this paper will address some of operating costs that are often times overlooked when attempts are made to continuously draw down producing reservoir pressures. For stripper wells in particular, there are a large number of wells that continuous drawdown strategies are not cost effective compared with simple conventional pump off control. This discussion will allow artificial lift professionals to make more informed decisions about operating their wells in a more cost effective manner.

BACKGROUND

While the original use of pump off control was intended to control the run time, the trend in pumping operations has been towards the increased use of pump off controllers with variable speed drives. In theory, reducing the speed of a pumping unit reduces average rod loading. In addition, keeping a well pumped off more often increases the average reservoir pressure drawdown near the wellbore. Outwardly, the primary benefits of run time control coupled with the secondary benefits of reduced equipment loading and greater production appear to be principles that all wells would benefit from over time.

However, the increased run time in many wells has offsetting costs that often times overlooked. The costs are related to inefficiencies from higher percentages of slippage and inefficiencies from gas interference. Stripper wells, in particular can experience dramatically higher pumping costs with variable speed pump off controllers.

Reservoir Engineering Principles: The two simplified models of inflow performance are the Productivity Index (PI) and the Vogel Curve. The PI method assumes that production is a linear function with the percentage drawdown of the total reservoir pressure. Production increases uniformly with the amount of total drawdown. This relationship is commonly used in wells with very little gas compressibility issues like waterfloods and water drive reservoirs. The Vogel method better recognizes the compressibility issues with increasing drawdown. In effect, incremental production improvements diminish as the drawdown approaches the maximum percentage drawdown because of the free gas in the reservoir near the wellbore.

There are many practical considerations when considering the implications of these models. First, many wells produce from layered systems. Some of these layers may behave with a PI tendency while other layers behave with a Vogel tendency. More importantly, the average static reservoir pressure in these layers and their corresponding permeabilies can vary dramatically. These two factors drive the shape and impacts of the overall production inflow curves and should guide the decision made by production engineers and artificial lift technicians.

The difficulty and cost to obtain measurements of the static reservoir pressure and permeability and applying this information lead many professionals to pursue a standardized approach to automation. However, the importance of of these reservoir properties cannot be emphasized enough for those serious about optimizing operating costs.

There are numerous techniques to estimate the range of static reservoir pressure. For example, if the well has been down for an extended period of time, the static reservoir pressure could be estimated from a fluid level and the appropriate estimated fluid gradients. A less costly indicator of static reservoir pressure can be estimated from the amount of fluid that is required to load the tubing. Initial fluid levels from swabbing after stimulation are yet another technique to bracket the understanding of reservoir pressure.

Qualitative estimates of permeability can be estimated with a variety of techniques as well. Typically, zones that have to be fracture stimulated are lower permeability than those that are produced with small acid jobs. The rate of bleed off of shut-in pressures following stimulation is another indicator of permeability. Those that bleed off more quickly tend have greater permeability.

Using a basic understanding of these two producing factors allows an artificial lift professional to categorize the well into 4 broad types as shown in Figure 1. Each reservoir type has important implications for the artificial lift professional, including:

Type A-High reservoir pressure, high permeability: This type of reservoir is typically characterized by the need to increase artificial lift capacity. Run time control is important for those occasions that the well pumps off. Slowing the pumping unit down is not generally a significant issue.

Type B-Low reservoir pressure, high permeability: This type of reservoir benefits the most from aggressive continuous pressure drawdown strategies. Run time control is important but the average reservoir pressure drawdown is perhaps as important. Slippage losses become a lesser consideration compared with the potential loss of production. These reservoirs also benefit the most from beam gas compression to remove as much backpressure as possible. One particularly extreme example of this type of reservoir had a reservoir pressure of 50-70 psia but in excess of 1000 millidarcy permeability. One of the wells in this field yielded an additional 30 BOPD of production by removing only 30 psi of backpressure. This type of reservoir will virtually always dramatically favor continuous pumping strategies.

Type C-Low permeability, High reservoir pressure: Type C properties will generally pump off and typically only need run time/pump off control. Variable speed control for continuous drawdown is not cost effective. The amount of back pressure that builds during shut in periods builds slowly and represents only a small percentage of the total reservoir pressure. These reservoirs are prone to have higher gas saturations near the wellbore that increase the compressibility of the system, making them more prone to Vogel type performance. The compressibility of the system and the slow buildup of pressure near wellbore mitigate the benefits of aggressive continuous running strategies.

Type D-Low permeability, Low reservoir pressure: This type of well is generally a low producer that will pump off quickly. However, like Type C wells, the costs of continuous pumping are generally not worth the additional capital and operating costs.

CONTINUOUS DRAWDOWN COSTS

Although the theory of continuous, automated drawdown is appealing, there are significant costs compared with simple, conventional pump off control, including:

Slippage: A well needs sufficient pump capacity to produce fluid to the surface plus the amount of fluid that slips or falls back down by the plunger of the pump. There have been various methods and research to estimate the volume that slips back down the hole through the plunger by barrel annulus. Slippage by the standing and traveling valves is considered negligible. As simple as this concept may seem, the majority of slippage occurs only when the well is actually pumping. For stripper wells, a major cost of a continuous drawdown operating strategy is the dramatically higher percentage of slippage requirements. Table 1 illustrates the additional pumping requirements to pump a given volume of fluid to the surface at 3 SPM continuously compared with pumping the same fluid to the surface at 8 SPM with a timer. The additional number of pump cycles affects the inhibitor programs, electrical consumption, and gearbox wear. This example is typical of lower rate wells in moderate depth wells where slippage is significant relative to the production. Limiting the run time adjusted slippage has a dramatic affect on total cost of operations.

Pump efficiency: In addition to slippage costs, continuous drawdown also loses pump efficiency by increasing the number of incomplete fillage cycles. A well that has been shut in for a period of time has more complete pump fillage. When the well pumps off with a simple controller, the well is shut in and allowed to build a fluid level over time until the pump starts again and repeats the process. In a continuous drawdown process, the number of pump off events increases based on the effectiveness of the controller automation. The increase in the number of these events increases the number of incomplete fillage events that drive a slight amount gas into the tubing. The greater the number of cumulative pump off events, the lower the overall efficiency.

RULES OF THUMB

A good rule of thumb is to use a shut in time that would allow no more than 5-10% of the static reservoir pressure to build up in the annulus while the pump is shut down. For example, if a reservoir has a static pressure of 1000 psi, 5% of this pressure would be 50 psi. If the gradient was 0.4 psi, this would represent about 125 ft of height. If this fluid height was in a well with 2-3/8” tubing and 5-1/2” casing, this height would be approximately 2.3 bbl based on 55 ft/bbl of annular capacity. If the well made 23BFPD, the well could be shut in for 1-2 hours when the well pumps off without materially hurting the production.

CONCLUSION

The application of basic reservoir engineering principles needs to be considered before the investment is made in variable speed drives that are coupled with pump off controllers. In particular, stripper wells where run time adjusted slippage is significant compared with the total production may dramatically favor less costly run time control approaches.

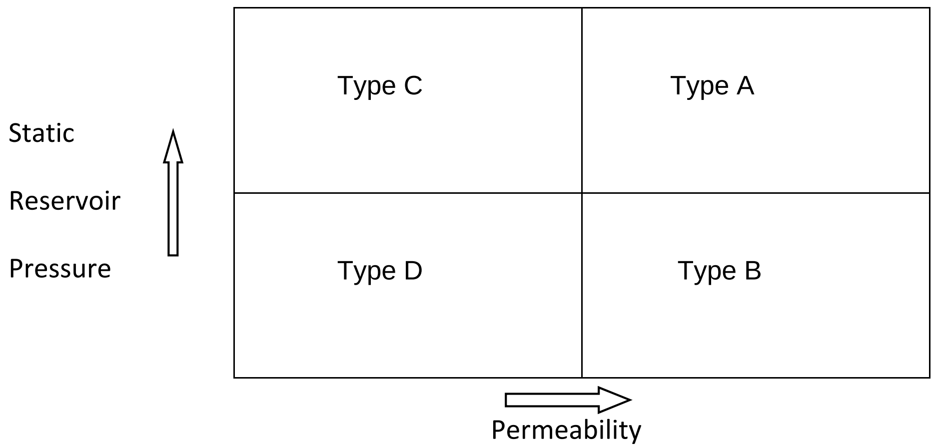

Figure 1 - Inflow Performance Curves

Table 1 - Slippage Comparisons

	Continuous	Conventional
SPM	3	8
Runtime	100	11.7
100% slippage B/D	32	48
Runtime adjusted slippage B/D	32	6
Net surface production	8	8
Rod loading %	76	89
Peak Gearbox Torque (Kin-lbs)	237	315
# strokes/day	4320	1347

Calculations based on QRod by Echometer using the Patterson Equation for slippage derived from research performed at Texas Tech University