# PUMP STROKE OPTIMIZATION: TWENTY WELL EAGLE FORD PILOT RESULTS

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ABSTRACT

"Pump Stroke Optimization" ("PSO") was developed to address problems encountered when using rod pump controllers (RPCs) on horizontal wells.  Current rod pump controller ("RPC") technology was developed for vertical wells, so their programming can struggle in the presence of flow regimes common in horizontal wells. RPCs in these conditions often call for frequent full spectrum speed changes and, the wells experience repeated low pump fillage events.

The common method operators employ to mitigate this problem is to manually reduce the maximum working speed setpoint in the RPC to a value slightly above that required to handle all the daily production.  This intervention can only be done periodically due to manpower constraints, despite the fact that well conditions vary constantly. Further, it is subject to human error, and even counterproductive if deliverability increases due to events such as coming off of downtime or offset fracs.  PSO supplants human intervention by regularly adjusting the maximum working speed based on analysis of several hours of observed pumping speeds and low pump fillage events.

Another key feature of PSO is the ability to modify the pumping unit speed within each stroke.  Since the PSO device controls the pumping unit speed, it can preferentially decrease the downstroke pumping speed.  This practice of having the downstroke slower than the upstroke reduces pump slippage, and allows additional time for gas to exit the rod pump's gas anchor.

These features enable PSO to lift production with fewer strokes, less power, lower gas interference, and improved pumping system dynamics in an economically meaningful way.  Field trials began in two Eagle Ford wells in March of 2015, with initial very successful results presented at an industry workshop in September 2015. The results of an additional 20 wells are presented in this paper.

INTRODUCTION

Prior to the invention of the RPC, pumping unit operators relied on labor intensive methods to control pumping unit speeds.  These methods would include among other things:

1.  "Shooting" fluid levels with shotgun and 45 shells
2.  Touching the polish rod as it fell to "feel" where the travelling valve was opening
3.  "Weighing" the well to get an analog dynamometer card
4.  Well testing

Prior to 1970, it was a normal practice for pumping units to be powered by engines instead of electric motors. The "pumper" or lease operator would adjust the governor setting as he deemed appropriate, given what little data was available.  This would change the engine RPM, and therefore the pumping unit SPM.  Due to the mechanical nature of the engine governor, there was no way to change the engine speed during the stroke, even if there was a way for it to know whether the pumping unit was on the upstroke or downstroke.

The quest for reliability and minimal downtime slowly pushed industry in the direction of electric motors. Still, the above methods were employed to set timers, which would turn the motor on and off intermittently instead of changing the speed.[1] Not until the advent of the "Pumpoff Controller" [1] as described by Westerman [2] would automated systems reliably detect and control "pump-off".  The "Pumpoff Controller" was later renamed "Rod Pump Controller", as the capabilities expanded over time.

The early "Pumpoff Controller" could only turn the motor on and off.[1]  It was not until the advent of the Variable Frequency Drive ("VFD") that the action of tuning the motor speed to match pump capacity with reservoir inflow became reality.[3]  Over the years since this paper[3] was written, some work has been done by industry regarding changing the speed multiple times *within* the stroke. An example of such work was given by Torseke, Polk, and Boren at the 2002 Southwestern Petroleum Short Course.[4] Goals were to optimize production, reduce maintenance through more favorable equipment loading, and decrease power consumption. However, until recently, the operation of VFDs at a constant speed throughout a given stroke has been the norm in industry.

PUMP STROKE OPTIMIZATION

The term "Pump Stroke Optimization" was created to address multiple improvements to pump operation. PSO should improve the operation of most any available RPC when applied to horizontal wells.

Vertical wells have dramatically fewer perforations and stimulations than horizontal wells and much improved phase separation of produced liquid and gas, resulting in much more stable conditions around the pump, particularly when the pump can be placed below perforations.  RPCs designed for vertical wells could make small speed changes that would quickly result in pump capacity matching well production.  In a horizontal well environment, slug and wave flow can result in regularly alternating conditions of primarily liquid and then primarily gas at the pump intake.  Each well's flowing behavior is a function of its trajectory, GOR, fluid rate, BHP, the varying inflow from individual perf clusters, and other factors. This erratic behavior misleads the normal RPC into making significant speed changes, causing pumping speeds to frequently cycle from maximum working speed to minimum speed with each slug or wave event.  The slowdown to minimum speed can often be accompanied by multiple strokes at much less than desired pump fillage.  This is detrimental to various components of the Beam Pumping System, as shown by Rowlan, Lea, and McCoy in "Overview of Beam Pump Operations".[5] In this paper, common methods to reduce the deleterious impacts of low pump fillage and tagging on the downstroke are presented.

To further explain how the typical RPCs operate in a horizontal environment, take the case of a horizontal well with portions of the lateral where the trajectory is rising, creating a low section (or even a heel), and a higher section. In this scenario, the horizontal lateral functions as a separator, with produced gas rising to the top of the higher section, and fluid flowing to the low section, then up the curve to the pump where it is pumped out.  At some point, the higher section will become gas filled, and expand into the lower section, and will ultimately push the liquid out of the lower section, causing liquid to quickly rise up into the vertical section where the pump is located.  This liquid slug will then be followed by the large volume of gas that had been trapped in the higher section.  The normal RPC will calculate high pump fillage when it sees the liquid slug, and start running the pumping unit faster and faster until reaching its maximum allowed speed. When the gas arrives behind the liquid slug, the RPC will calculate poor pump fillage, and decrease speed rapidly in the attempt to protect the rod pumping system. In this way, the response of RPCs to flow regimes typical of horizontal wells causes an extreme amount of cycling between Maximum and Minimum speed setpoint, never converging on the optimal speed.

The common method operators employ to mitigate this cycling problem is to manually reduce the maximum working speed setpoint to a value slightly above that required to handle all the daily production.  The minimum working speed is similarly reduced at this time, forming a "window". Inconsistencies in application of this intervention can be a major source of uncertainty to a failure prevention program, and is counterproductive should the well see increased deliverability due to events such as downtime or offset fracs.  PSO replaces human intervention by regularly adjusting the maximum working speed based on analysis of several hours of observed pumping speeds and low pump fillage events.  The PSO device never goes on vacation, gets busy with other activities, or goes to sleep at night, and it never enters erroneous setpoints.

To seek out the optimal speed, PSO logic attempts to tune the pumping unit speed to match the average inflow over a multiple hour period.  It will not over-react to high pump fillage resulting from a slug of fluid being pushed from the lateral by an expanding gas "piston", and cause speed increases.  Conversely, when the fluid slug has passed, and the higher section of the lateral is "blowing down", the PSO will not change any speed settings.  Yes, the PSO will reduce the pumping speed temporarily to the operator set minimum working speed.  However, the PSO device will attempt to tune the frequency of these events to be in line with the historic slug behavior of the well, using

proprietary algorithms to do so. Pumping too fast will cause excessive cycling between minimum and maximum speeds, when the goal should be to have the cycling synchronize with the well's natural behavior.

The multiple hour period utilized for this pilot test was to tune the maximum and minimum working speeds four times per day. Since this value was very successful in getting the tuning algorithms to converge, other values were not tested.

### PSO Benefits

The primary benefits of Pump Stroke Optimization are:

1. Decreased Pump Slippage (less strokes per day)
2. Increased Pump Fillage (less strokes per day)
3. Higher Minimum Rod Loads
4. Power Savings

### Pump Slippage

Recent industry presentations dealing with pump slippage [6] point out that pump slippage only occurs when the travelling valve is closed. This would include the entire upstroke, in which case each volume unit of slippage results in a similar volume unit not entering the pump through the standing valve. This is viewed as deleterious slippage [8], as it reduces system efficiency, *and only occurs during the upstroke*.

In cases of incomplete pump fillage, the travelling valve may be closed for a portion of the downstroke. However, this does not result in less fluid entering the pump, only in fluid entering between the standing and travelling valves. This action will increase pump fillage, and results in the travelling valve opening sooner. In this situation, the pump slippage is deemed beneficial, *and only occurs during the downstroke.*

Based upon the assertion that upstroke slippage is deleterious, and downstroke slippage is beneficial, these realities can be maximized to optimize the pump stroke by limiting the duration of the upstroke, and increasing the duration of the downstroke.[7]

Previous work done by industry to model downhole pump slippage resulted in equations that assume that upstroke travel time and downstroke travel time are equal. While this would be true for conventional geometry pumping units, it is not true for alternative geometry pumping units. Chambliss pointed this out in his thesis [8], and also provided an equation to adjust pump slippage ($B$) for adjusted geometry units as follows:

$$B_{Adjusted} = \frac{Degrees_{UP}}{180} B_{Calculated}$$

Building on Chambliss's work to account for geometry related unequal travel time, a revised equation is proposed to account for situations where upstroke travel time ($T_{Upstroke}$) and downstroke travel time ($T_{Downstroke}$) differ on account of prime mover speed changes, as well as alternative geometry pumping units:

$$B_{Adjusted} = (2 \times T_{Upstroke} \times B_{Calculated}) / (T_{Downstroke} + T_{Upstroke})$$

For example, a well with a conventional pumping unit operating at 3 SPM has a 20 second stroke duration, of which the upstroke travel time and downstroke travel time are 10 seconds each. If the upstroke accelerated to 6 SPM, the upstroke travel time would be reduced to 5 seconds. Similarly, if the downstroke was decelerated to 2 SPM, the downstroke travel time would be 15 seconds. In this latter case, the total stroke duration is still 20 seconds (5 plus 15), but the upstroke travel time is half of its previous value. The original upstroke duration was 50% of the total stroke duration, but has been reduced to 25% of the total stroke duration. The implication is that since the pump is

only leaking for half the time it was previously leaking (5 seconds out of 20 instead of 10 out of 20), that the amount of leakage will see a proportional reduction of 50%.

## Increased Pump Fillage

There are three components of Pump Stroke Optimization that result in increased pump fillage. Using the above example, but instead evaluating the downstroke, the downstroke duration increased from 50% to 75% of the total stroke duration, making it logical that downstroke slippage has increased. While this does not impact system efficiency since the standing valve is closed, it does move the load release to an earlier position in the downstroke, which is desirable due to the lower torque factors.

The second component is a theoretical component, and is not related to the gas anchor's ability to keep gas from entering the gas anchor. Untold industry effort has been unleashed on methods to make a better gas anchor, but ineffectiveness is the end result because of a lack of comprehending the fundamental problem. The problem is not simply how to keep gas from entering the gas anchor, but more importantly how to handle the gas that is evolving realtime from the oil. Consider that the oil has never had a chance to equilibrate, or breath, on its climb to higher elevations in the vertical section of the horizontal well where the gas anchor is located. When it enters the gas anchor, which it would not do unless the pressure was lower, it is still "boiling". So, not only must the gas anchor get rid of gas brought in with this oil, but additionally, the gas coming out of solution.

In the above example with a pumping unit operating at 3 SPM, the downstroke duration has been increased from 10 seconds to 15 seconds. This gives 5 additional seconds for the gas to be liberated from the oil, and exit the gas anchor. The gas that exits is replaced by fluid, which results in increased pump fillage, and therefore more fluid pumped per stroke. It does beg the question about how much gas can be liberated in 15 seconds, but this would be dependent on the oil components, pressures, and temperatures.

The third component is also theoretical, and relates to the behavior of evolved gas bubbles that were not able to exit the pump, but are instead drawn into the pump. Given that the evolving gas bubbles in the gas anchor are rising during the downstroke, the volume percent of gas will be lower at the bottom of the gas anchor, and higher at the top, simply due to the rise of the gas bubbles once generated. In turn, when this gassy fluid is drawn quickly during the upstroke from the gas anchor into the rod pump, the fluid in the top of the pump will have less gas content, and the fluid at the bottom will have the most gas content. During the quiet downstroke, the gas bubbles will have 15 seconds to either rise up inside the pump (and get smaller as they are compressed), or go back in solution as the internal pump pressure increases prior to travelling valve opening. The further into the downstroke the gas compression step takes into the downstroke, the *less likely that collapsing components of the gas bubble will reside in the bottom of the pump.*

The relevance of this is simple. When the upstroke begins, the fluid between the standing and travelling valves is less likely to evolve gas (upon the pressure decrease associated with plunger rising), simply because these components had a chance to rise into the upper portions of the pump. The end result is that the standing valve opens sooner because of this additional downstroke time, resulting in more fluid entering the pump. This is characterized by a steeper load increase on the left side of the downhole dynamometer card, and signifies a longer net plunger stroke, without actually having a longer travel. This results in increased pump fillage, and therefore more fluid pumped per stroke.

Considering the implications of these two theoretical components leads to the idea that pumping fulltime instead of intermittently in horizontal wells may be advantageous, as the idle time is spread across every downstroke to increase the time available for gas to evolve then exit the pump, and to provide for earlier standing valve opening. Both of these result in increased pump fillage, and therefore more fluid pumped per stroke. This in turn results in less strokes per day for the same production, which should reduce the wear on pumping system components, leading to longer time between downhole failures.

We are unable to directly observe what is happening in the downhole pumps and gas anchors, and we have not attempted process modeling to compare or predict the contribution of these two theoretical components, but PSO testing has provided data to suggest that PSO benefits from these effects. First, in multiple horizontal wells by

virtue of downhole pumpcard observations, and second, by otherwise unexplainable increases in pump fillage as well as many less strokes per day.

## Higher Minimum Rod Loads

Predictive rod pumping design programs show that minimum rod loads are usually increased when the downstroke is slowed. Elevating the minimum rod load does several beneficial things:

1. Higher minimum loads when realized at the lowest portion of the rod string can result in less rod buckling due to compressive forces being reduced.
2. Per the Modified Goodman Diagram, an increase in the minimum rod load typically results in the allowable maximum rod load being increased by typically 56% of the minimum load increase.
3. A common industry indicator of minimum rod load over maximum rod load increases favorably when the minimum load increases, without the maximum load appreciably increasing.

## Electrical Power Savings

Dramatic speed changes every stroke have the potential to waste electricity, especially with VFD's that do not include the ability to "regen" the kinetic energy realized through slowing down the motor. If VFD's without this capability cannot store this converted kinetic energy in the DC bus capacitors, then they divert the excess electrical energy to "Dynamic Braking Resistors", which turn it into wasted heat.

In spite of this, several factors contributed to dramatic power savings being observed in PSO field trials. First, less strokes per day from decreased pump slippage and increased pump fillage has the potential to reduce electric power consumption. Second, since most VFD's utilizing PSO are significantly oversized compared to the actual motor loads, the size of the capacitor as a function of motor load provides a relatively large sync to contain this electrical energy. The same capacitive electrical storage that allows VFD's to "ride-through" brief power interruptions can potentially store the energy regenerated by slowing down the motor. It then gives this power back during the downstroke, and possibly when the upstroke speed increase occurs.

## METHODS AND PROCEDURES

An expanded twenty well Eagle Ford pilot test was begun December 3 of 2015. Rather than picking wells that were pumping in the PSO service recommended range of 2 to 5 SPM, a wide range of production rates were chosen by operator personnel, ranging from 0.85 to 8.13 SPM. Eight of the twenty wells were operating intermittently (turn off motor when low fillage occurs), with seven of the eight operating at average speeds of 2 SPM or less. All eight were converted to full time operation as part of this pilot, with minimum pumping speeds of 1.25 SPM. In order to average 2 SPM or less pumping speed, the upstroke speed is severely limited when the downstroke is 1.25 SPM. Therefore, the actual PSO controlled speed increase on the upstroke was less than the desired 4 SPM for the seven wells. This placed limitations on the benefits derived from a faster upstroke, resulting in the expectation that the performance improvements might not be as good from these seven.

On the other end of the pumping speed spectrum, four wells were pumping faster than 6.2 SPM. If the pumping system was designed to operate at speeds up to 9 SPM, then averaging 6.2 SPM could easily be accomplished by operating at 9 SPM on the upstroke, and 5 SPM on the downstroke. Due to the pumping depths and large unit sizes for this Eagle Ford operator, maximum pumping speeds were 7.5 SPM for most units, with 9.0 being the upper end. Therefore, the actual PSO controlled speed decrease on the downstroke was less than the desired 4 SPM for these four wells. This again placed limitations on the benefits derived from a slower downstroke.

Despite the expectation that a total of eleven of the twenty wells were not good PSO candidates, the pilot test went ahead with these wells for two reasons. The first was the negligible cost to install or subsequently remove the PSO devices, which took less than an hour to install, or remove. The second reason was that perhaps even "poor" candidates for PSO might still achieve enough benefit to be worth the minimal cost of installing and operating the PSO device. After 45 days of operation, the following performance indicators were reviewed by the operator to determine overall success or failure:

1. Algorithm Convergence (Indicating successful PSO device supplied pumping speeds, and less operator involvement )
2. Pump Fillage improved by 8% or more
3. At least 5% Fewer Strokes per day without production loss
4. At least $100 per month electric power savings
5. Minimum Rod Load Increased by 1000 pounds or more
6. Changed from Intermittent pumping to full time operation
7. Increased production

To be judged as successful, it was not necessary to show success in all 7 indicators.  For example, if the well resulted in increased production because the algorithm convergence pumped the well harder without reducing pump fillage, this would receive a "success" rating.  Less strokes, less electric use, and rod load improvements were less material in comparison to the production increase.  Conversely, as production increases were not expected in wells with multiple low pump fillage events, then less strokes per day without production loss, with less electric power use could be considered a success.

The data was obtained using standard industry SCADA and data analysis software, as well as manually reading power meters.

## OBSERVATIONS
Due to the practical limitations of multi-color data graphs in a black and white medium, captured field data will be summarized in black and white.

### Algorithm Convergence

All twenty PSO devices were able to converge using the existing onboard algorithms.  Confirmation of whether an algorithm will converge is easily determined by observing "Average SPM", as well as high frequency SPM data. If the pumping speed drops to the minimum working speed, or conversely increases to the maximum working speed, then the algorithm is not working correctly. The steady oscillation in a range that varies from 1 to 2 SPM indicates that the algorithm is working, as does a steady frequency of sub-setpoint pump fillage numbers.  An example of convergence for Well D is shown in Figure 1. Note that PSO operation began on December 3.

An example of an algorithm that diverged is shown in Figure 2. Note the first downward staircases beginning on January 24 after a six month period of convergence. (This well was one of the first PSO tests last year, and not in this 20 well group.) It was reset on January 27, and failed again to converge as shown in the second staircase. The algorithm was reversed, with convergence subsequently being achieved.

### Pump Fillage Increase – 8%

Pump Fillage increases exceeding 8% were realized for 9 of the 20 wells, as shown in the black bars of Figure 3.  Also shown in gray is the percent stroke reduction for these same wells.  Observe that increased pump fillage does not appear to be related to the percentage stroke reduction, which was not expected.

### Stroke Reduction – 5% without production loss

Stroke reductions of 5% or more were achieved on 8 of the 20 wells. Figure 4 depicts this in two ways.  First, the bar graphs of average SPM before and after PSO implementation, and second, the percentage of stroke reduction averaged during the pilot test shown in the dashed line graph.

It is worth noting that the first seven wells were the ones that had been operating intermittently, and were averaging 2 SPM or less prior to PSO testing.  The eighth well (S), which had been averaging 2.7 SPM operating intermittently, had a 31% drop in stroke count when placed on continuous PSO operation.

It is also notable that well C, which was operating at 5 SPM, was the last well to see double digit percentage stroke decrease (10%).  The exception to this is Well F, which was running at a "SPM Before" of 6.2 and saw a 25% stroke

reduction. This is an anomaly related to inducing casing flow, however, since this was a result of PSO, it is counted as a success. (Details presented later.)

Well H had been operating at 6.5 SPM, but was only able to realize a 2.5 SPM downstroke slowdown without risking production loss. Although this was below the desired value of 4 SPM, a stroke reduction of 5% was still realized, which accounted for 421 strokes per day, or almost 154,000 per year.  This was judged to be significant, and made the cut.

Well J, with an "SPM Before" of 8.13 and an "SPM After" of 6.98, saw a 14% stroke reduction.  However, this value was dropped to zero as oil production decreased by 9 BOPD. The PSO device was turned off following this evaluation to regain production.

Similarly, Well N with an "SPM Before" of 6.7 and an "SPM After" of 6.41, saw a 4% stroke reduction. It also saw an oil decrease of 10 BOPD that was subsequently proved to be natural well depletion. However, this was arguable at the evaluation, so the PSO device was moved to another well due to this uncertainty as well as other performance indicators such as pump fillage, stroke reduction, and higher minimum loads being below the cutoff values.

### Power Savings of $100+ per month

Power meters were only available for 8 of the 20 wells, with the remainder being on centralized power systems without individual metering.  Of these 8 metered wells, 6 exceeded the $100 per month power savings cutoff, with half of these exceeding $200 per month.

Figure 5 shows that electric power savings were comparable to percentage stroke reduction with two exceptions. Other than Well A and Well I, remaining wells with a 10% stroke reduction saw at least $100 a month of power savings. Well I (one of the intermittent pumping wells) realized a $190 power savings, but no stroke reduction. Conversely, Well A realized a 14% stroke reduction, yet only a $20 power savings, and are considered anomalies.

For the purposes of this evaluation, since power data was only obtained on 40% of the pilot wells, yet the data shows a strong correlation to a 10% stroke reduction realizing $100 or more power savings, this correlation was extended to the 20 wells.   Since 8 of the 20 wells had stroke reduction percentages exceeding 10%, this value was used instead of the actual value of 6.

### Minimum Rod Load Increased by 1000+ pounds

There were 12 wells of the 20 that achieved minimum rod load increases exceeding the cutoff of 1000 pounds. This data is shown in Figure 6. The last three wells showing no minimum load increase were from the group of four that had pumping speeds prior to PSO exceeding 6 SPM, and were not able to achieve much downstroke speed reduction.

The percentage pump fillage increase was included in the Figure 6 graph to show if there was any relationship between pump fillage and minimum load increase, and there apparently is not.

In Figure 7, a graph of the ratio of Minimum Rod Load to Maximum Rod Load is presented.  This is provided to show that the minimum rod load increase shown in Figure 6 was not accompanied by an excessive increase in the maximum rod load.  As can be seen, the ratio of these two loads is only minimally lower after PSO implementation for Wells G and J.

### Changing from Intermittent pumping to non-stop Operation

As stated earlier, 8 of the 20 pilot wells had been operating intermittently, turning off for a preset time period when pump fillage dropped to certain low levels.  Because a non-operating pump has no slippage, PSO operation was not able to improve on pump slippage for intermittent wells.  However, subsequent additional testing using a secondary fillage setpoint appears to enable PSO operation at the primary setpoint, yet allows the pumping unit to turn off for a preset amount of time when the fillage drops below the secondary setpoint. This is an area for additional testing.

There are multiple possible benefits from operating continuously instead of cyclically. Some of these would include:

1. Prevention of sand and other debris falling down and sticking the downhole pump
2. Prevention of motor "breathing" in humid environments when it turns off then cools, possibly condensing water (detrimental to bearings and winding integrity).
3. Reduction in kW billing demand from lower rate of power consumption
4. Potential for leaving production behind

Well L, which had averaged 1.75 SPM before PSO, and 1.95 SPM after PSO, did not see improved pump fillage. This is because at the Minimum Working Speed of 1.2 SPM, pump fillage events were regularly below 60%. In addition, the well saw 11.5% more strokes per day. This well was deemed a failure, with the PSO device being relocated to a better candidate.

Well B was similar, with a 0.85 SPM before PSO speed, and a 1.67 SPM after PSO speed. The problem of sub-60 fillage events was solved by reducing the stroke length of the pumping unit. This was responsible for increased pump fillage of 17%, but with 96% more strokes per day, the decision was made to return it to intermittent operation.

This left 6 of the original 8 wells on intermittent operation remaining on fulltime PSO controlled operation.

Increased Oil Production

Well E was an intermittently operated well that saw its production increase by 9 BOPD, and is an example of item 4 listed in the preceding section as "Potential for leaving production behind". The 9 BOPD increase is based on daily production numbers for the 90 days pre-PSO implementation, and 45 days post-PSO. Although this in itself was justification enough for PSO, the well also had 5% higher pump fillage, and 1200 pound higher average minimum rod load.

The 20th Well

Data presented so far has been for wells A through S. The remaining well T was found to have a significant standing valve leak immediately upon PSO implementation. This manifested during the extended duration of the PSO downstroke, allowing all well fluids to drain from the pump prior to the bottom of the stroke being reached. The result of this was very low pump fillage, which in turn caused the PSO algorithms to slow the pumping unit down. This further exacerbated the problem, and resulted in oil production dropping from 30 BOPD to zero.

After running this way for a week, the operator placed the well back in fixed speed operation at speeds high enough to overcome the standing valve leak. While an energy wasteful practice that also resulted in additional wear cycles on the downhole equipment, it allowed postponement of well servicing for a short period. The well subsequently experienced a downhole failure 60 days after being returned to fixed speed operation. The well operator has left the PSO device installed in anticipation of returning the well to production. It is worth noting that in the seven days that the PSO was in operation, the algorithm reached convergence, and the minimum rod load increased by 2000 pounds. Only the convergence was included in the preceding performance indicator evaluation.

RESULTS

The graph presented in Figure 8 summarizes the number of wells that achieved each of the seven desirable performance indicators. This information was assembled following a PSO pilot evaluation session held by the well operator.

To do the evaluation, the well operator assembled a team of three production engineers and four artificial lift technicians, and reviewed all the observed well data realtime on large monitors. Each person had their own opinion on the relevancy of each performance indicator. After reviewing these indicators on a well by well basis, the group voted on whether the PSO installation was successful, marginally successful, or not successful.

Summarizing the results, the operator deemed ten wells highly successful, five marginally successful, and five not successful.

Following this evaluation meeting, the following actions were taken by the operator:

1. PSO devices were relocated from previously intermittent pumping wells B and L that were judged as not successful.
2. PSO devices were relocated from well J and N (which had the two fastest pre-PSO pumping speeds of at 8.13 and 6.7 SPM) that were judged as not successful.
3. The PSO device in well T is not being operated until the downhole failure is repaired, and then it will be evaluated.
4. The remaining 15 PSO devices continue to operate. The 5 marginally successful wells are still using the PSO devices due to its low cost, and a desire to keep even marginal performance indicator increases.

### Explanation of Well F Behavior

As mentioned earlier, Well F realized a 25% stroke reduction, despite having a "Before PSO" average of 6.2 SPM, outside of the 2 to 5 SPM expected success window. Normal production for this well was 110 BOPD, with the RPC calculating an inferred production of 10 to 15 BOPD higher than this. The well had history of flowing up the casing annulus for a few days per month, which would cause the inferred production value to instead be 20 BOPD lower than the actual production.

Upon PSO implementation, the inferred production value during annular flow of 20 BOPD lower increased to 55 BOPD lower than actual production, with the periods of annular flow lasting typically a week instead of a couple of days. The annular flow would only stop when the casing annulus was closed every 14 days for chemical treatment. Following this, it would take about a week to resume annular flow. Had it not been for these chemical treatments, the achieved stroke reduction would likely have been 50% instead of the realized 25% reduction. This is because upon initiation of annular flow, the average pumping speed would drop from 8 SPM down to the 3 to 4 SPM range.

The explanation offered for this behavior is related to PSO causing less gas to enter the pump, and therefore flow up the casing annulus. This increases the GOR of any oil flowing up the annulus, further lowering the bottom hole pressure, encouraging even more annular flow.

### CONCLUSIONS

1. Pump fillage and pumping speed data show that the PSO algorithms are able to correctly set the maximum and minimum working speed setpoints to maintain the desired frequency of low pump fillage events within an equipment safe fillage range (Figure 1 and 2).
2. Stroke reduction data supports the PSO developer recommendation of 2 to 5 SPM pre-PSO average pumping speed as a good screening tool for PSO success.
3. Pre-PSO average pumping speeds up to 6.5 SPM can sometimes result in significantly less strokes per day, as evidenced by well F and H.
4. Pre-PSO average pumping speeds above 8 SPM resulted in lost production in the one well where it was tried (Well J).
5. Greater stroke reductions were achieved when larger differentials between upstsroke and downstroke pumping speed were obtained, e.g. 4 SPM differential.
6. Since increased pump fillage did not correlate to a reduction in stroke count (Figure 3), the primary factor in reducing stroke count by default is decreased pump slippage. This is evidenced by larger stroke count reductions being seen where upstroke to downstroke speed differential reached desired values near 4 SPM.
7. Negligible correlation exists between pump fillage increase and minimum load increase, leading to the conclusion that downstroke speed reduction is the primary reason for minimum load increase.
8. The percentage of electrical power reduction is closely proportional to stroke reduction per Figure 5.
9. Significant minimum rod load increases were obtained in all wells where the upstroke to downstroke speed differential reached desired values. Maximum rod load increases were minimal in comparison to the minimum increases, as shown in Figure 7.

## DISCUSSION

The primary objective in developing Pump Stroke Optimization was creating a method for autonomous optimal setting of maximum and minimum rod pump working speeds.  A secondary objective was to optimize the operation of the rod pump and sucker rod string within the stroke (which is done by operating the upstroke at a fast speed, and the downstroke at a much slower speed - typically 3 to 5 SPM slower). This "fast upstroke / slow downstroke" solution is responsible for multiple benefits as detailed above.

Pump Stroke Optimization is focused on optimizing the operation of the rod pump and sucker rod string. Gearbox loading, prime mover loading, and VFD loading are of lesser importance, but are protected by making the speed changes at the top and bottom of the stroke, where gearbox torque factors are so small that well loads are not seen by the gearbox, motor, nor VFD. Since significant speed changes result in high rotary inertial torque loads that are necessary to consider when evaluating gearbox reducer torque [9], it is a questionable practice to make these speed changes while gearbox torque factors are high as in mid-stroke. The safer approach is to make speed changes at the top and bottom of the stroke, when torque factors are negligible.

The reason for seeking improvements to the operation of the rod pump and sucker rod string is the great expense of repairing downhole failures, as well as the downtime related production loss. If the PSO modified pumping speed can keep a well "on its curve" with fewer strokes, and demonstrate as good or better pumping dynamics in terms of rod loading and other features associated with failure rates, the reduction in cycles will be an unambiguously positive factor in increasing time between failures.  A secondary benefit comes in the form of electric power savings, which is easier to observe over the short run than reduced failures.

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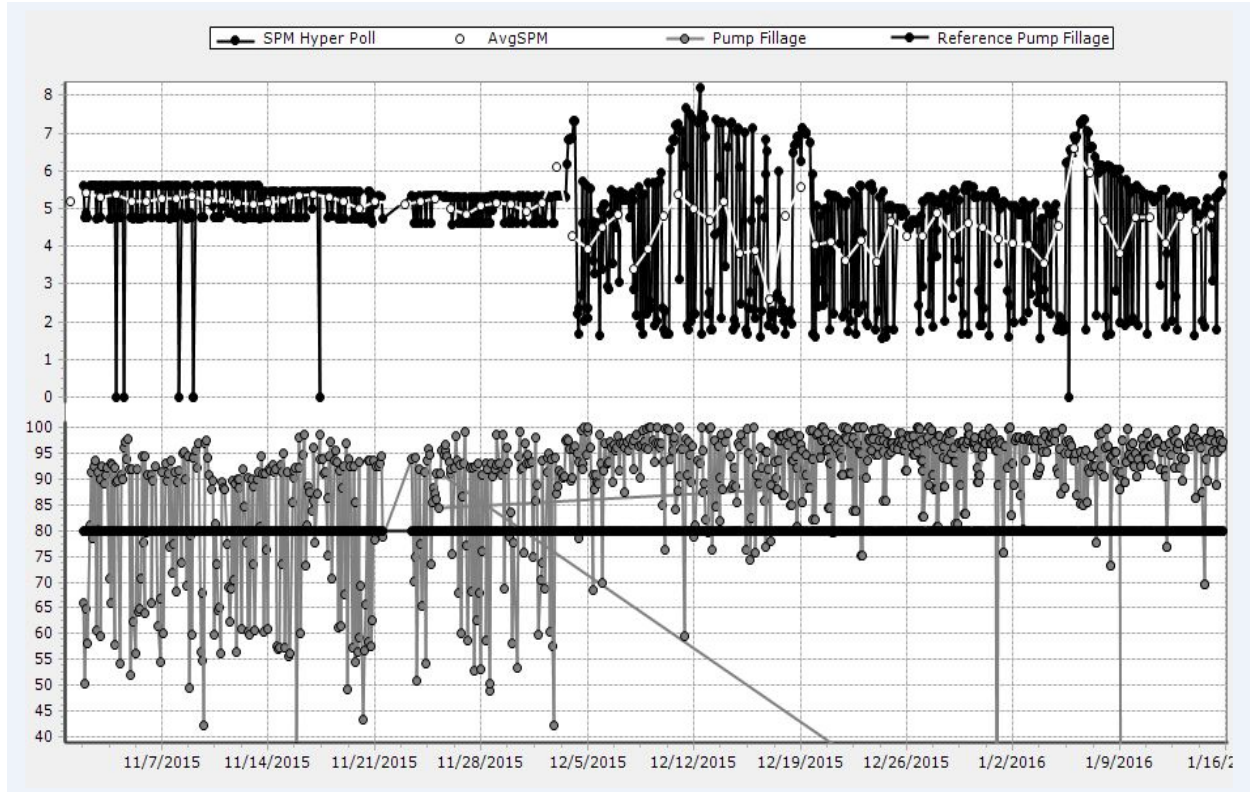
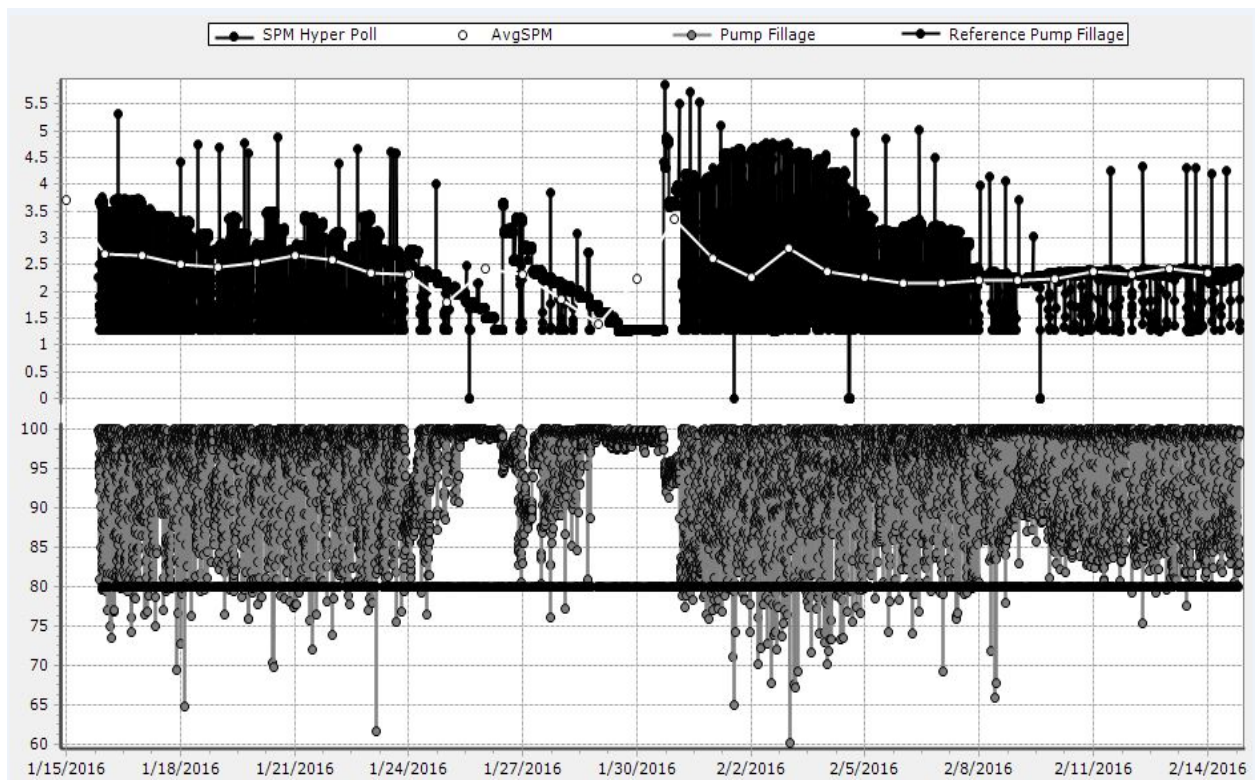Figure 1 – Example of algorithm convergence.  PSO operation began 12/3/2015



Figure 2 – Example of Divergence, Reset, Divergence, Algorithm change, then Convergence
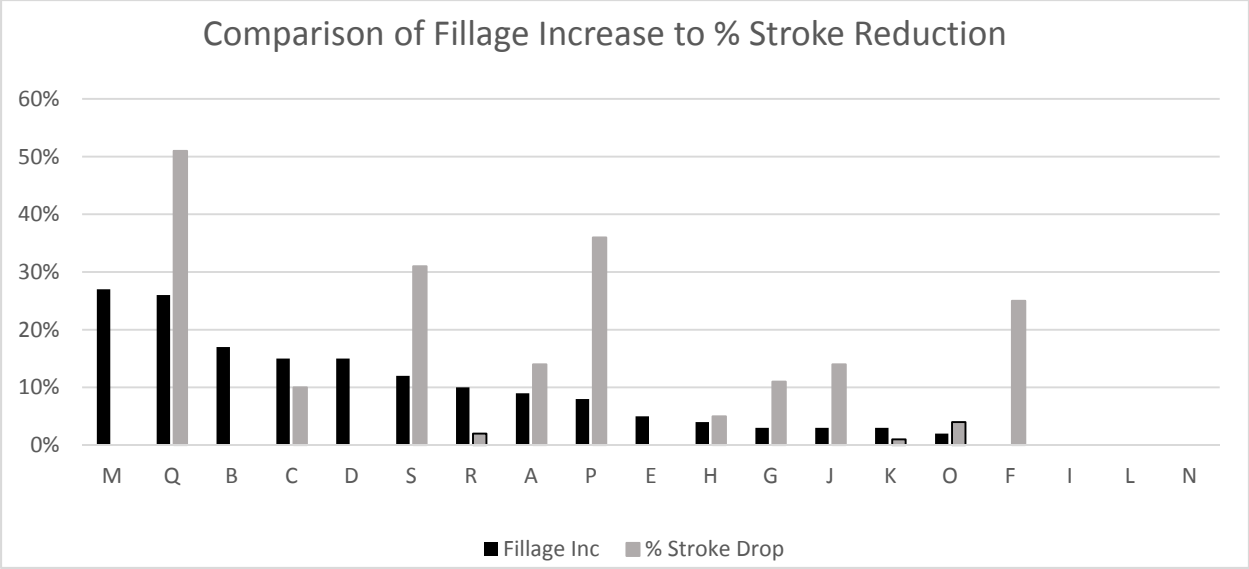
Figure 3 – Comparison of Fillage Increase to Stroke Reduction
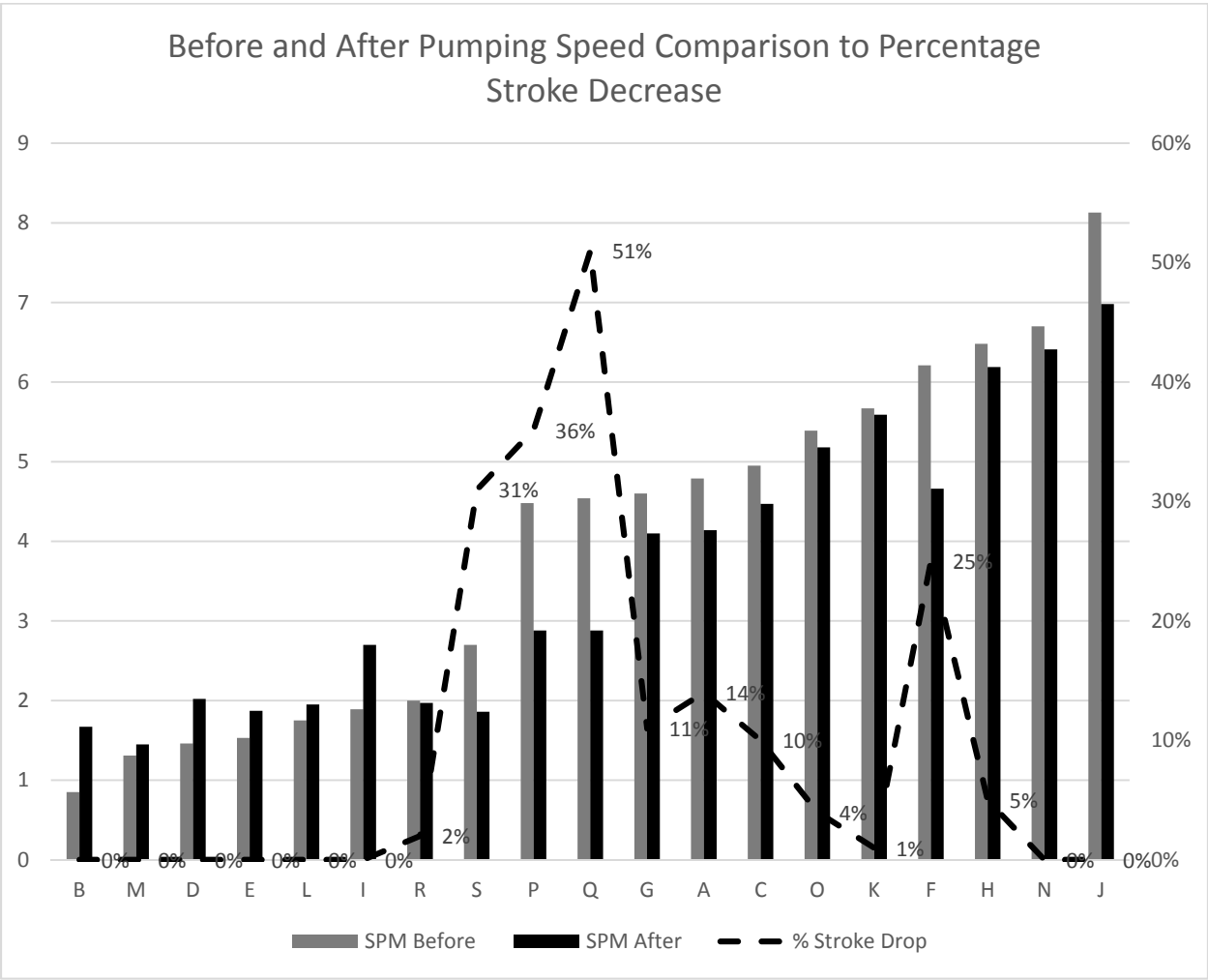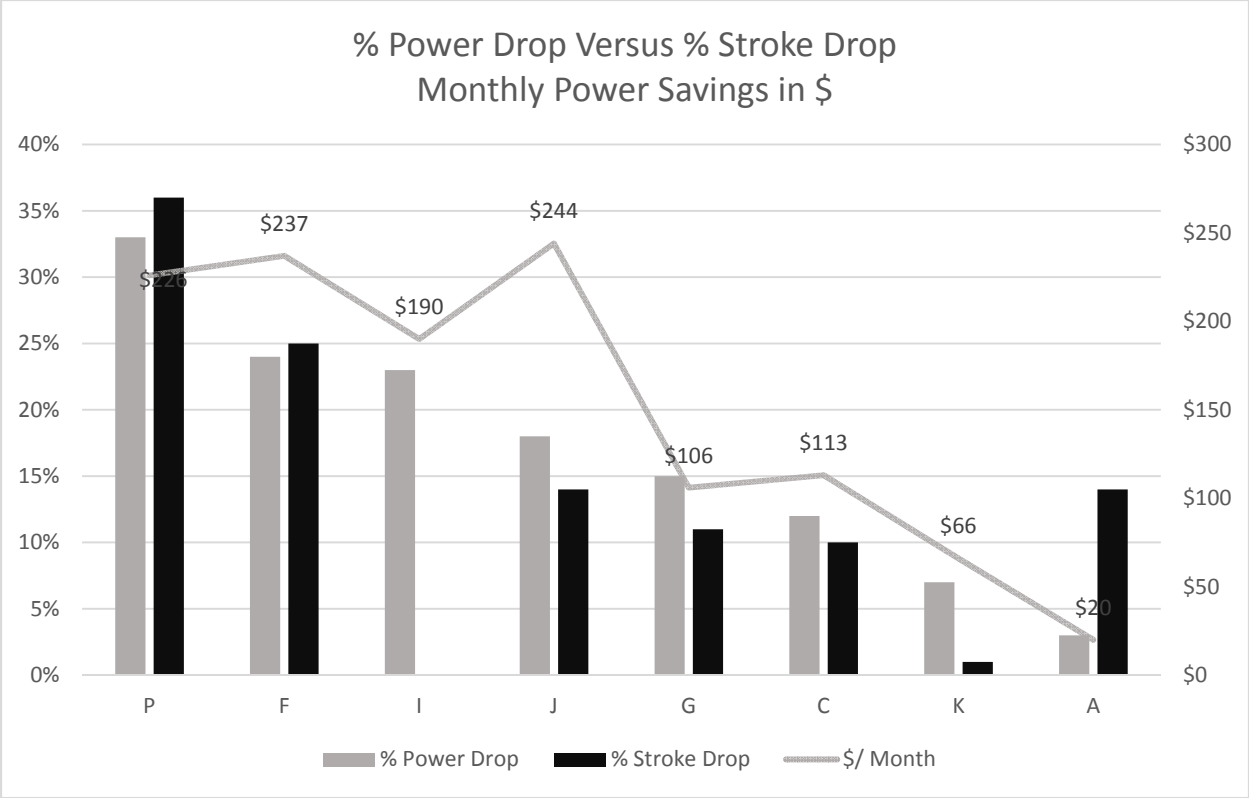


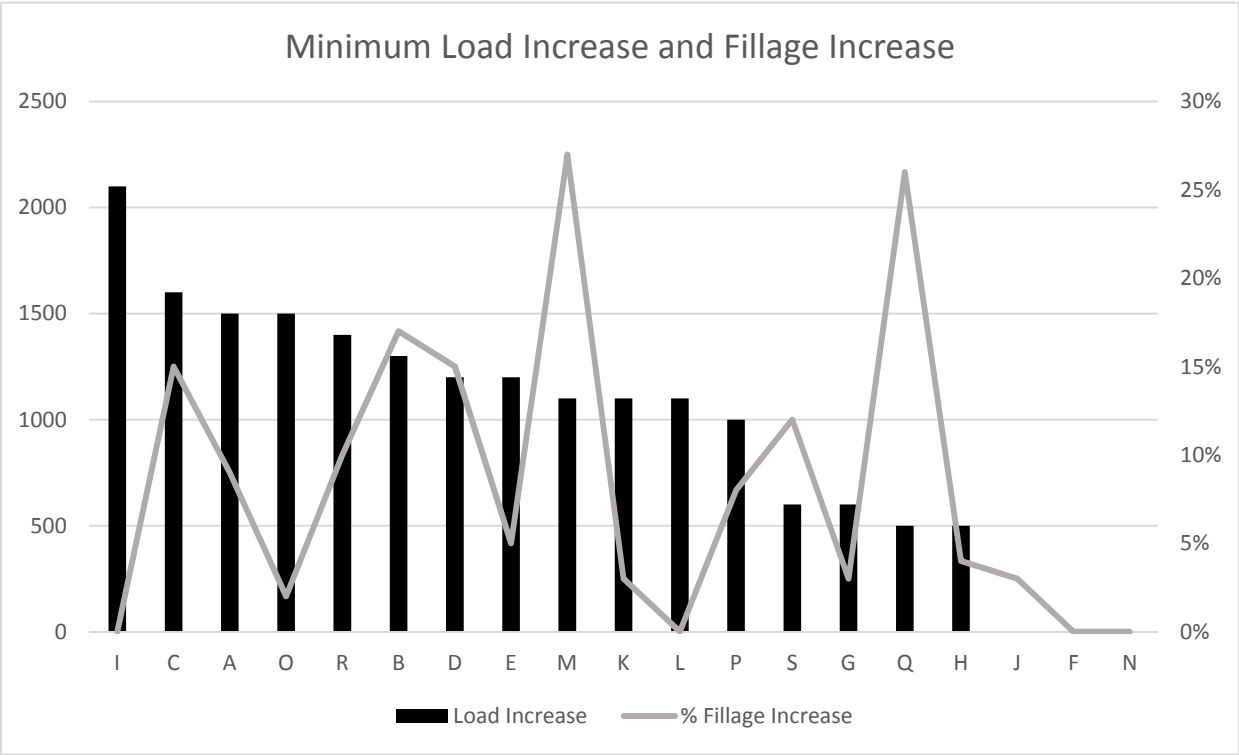Figure 4 – Stroke Reduction

Figure 5 – Electric Power Savings
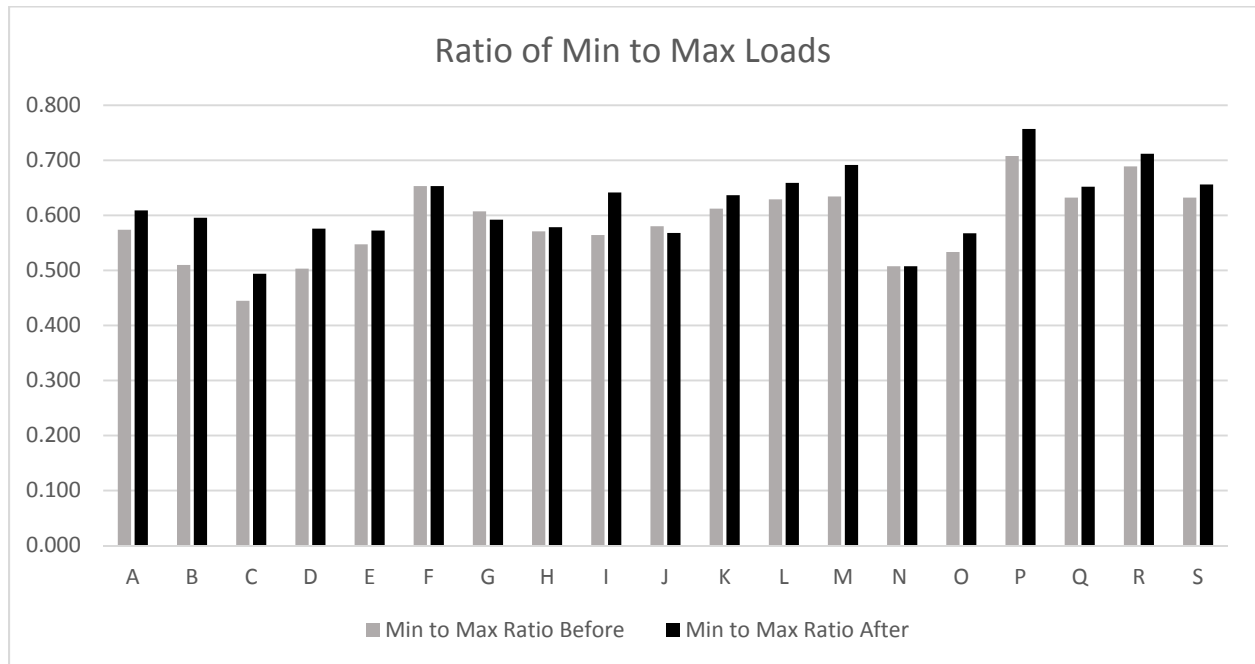
Figure 6 – Minimum Load Increase



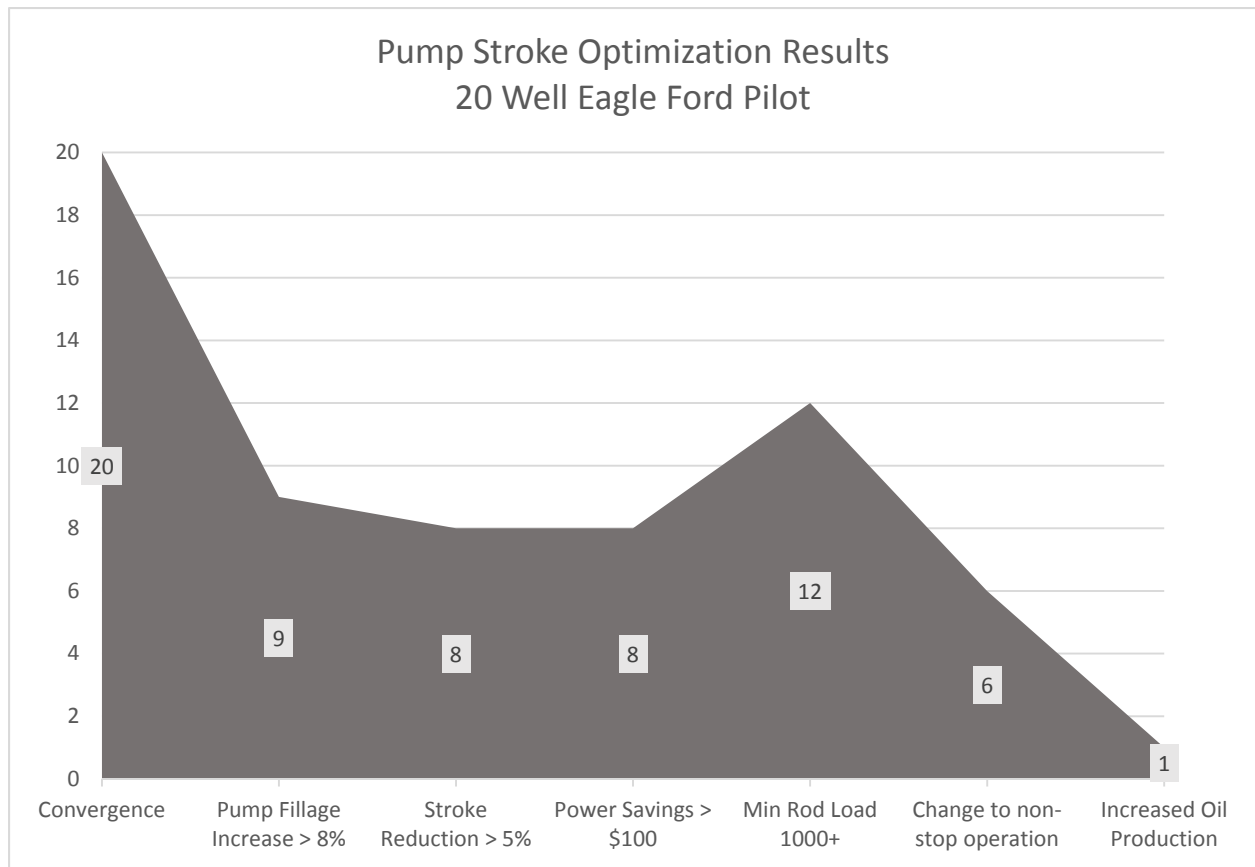Figure 7 – Ratio of Minimum Average to Maximum Average Rod Loads



Figure 8 – Summary of PSO Performance Indicators for 20 wells