IMPROVING ARTIFICIAL LIFT STRATEGIES IN YESO HORIZONTAL WELLS

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ABSTRACT

Many operators in the Permian Basin have moved from drilling vertically to developing leases with horizontal drilling. After implementing a horizontal drilling program, three critical challenges emerge: 1) selecting the most efficient means of initial production; 2) using a rod pump design without experiencing gas interference or losses in volumes; and 3) handling a horizontal well at pumped-off conditions. Drawing the well down as quickly as possible is ideal for generating the best economics. The initial investment and operating costs of the artificial lift system must also be considered when performing economic analysis. Rod pumping horizontal wells to produce the high rates that the model describes is challenged by gas interference which has resulted in the following: rod and tubing wear, upper buckling tendencies, increased man hours trying to resolve problems, and a loss in production. When pumped off conditions occur while rod pumping from the kick off point, a noticeable decline in production can be observed. In low pressure reservoirs, lowering the pump into the curve can prove to restore or even increase production rates. By studying past cases of producing Yeso horizontal wells in the New Mexico Shelf Platform, COG has been able to select an optimally sized ESP, smoothly convert to a rod pumping system to achieve pumped off conditions, and continue to produce in the curve to avoid losses in production.

INTRODUCTION

COG has observed more than 50 Yeso horizontals from initial to mid-life (2-3 years) production. The average full section Yeso horizontal well is based on a 200 - 250 MBO EUR model that has an initial hyperbolic decline of 52 - 72% decline and assumes a 6% exponential decline after the four years of production for the remainder of the model. Yeso wells are drilled with a tapered casing string and a true vertical depth of less than 5200'. The wellbore diagram in Figure 1 illustrates how the wells are generally constructed on the New Mexico Shelf Platform. Initial production rates vary from 1,400 BFPD to 2,400 BFPD with oil cuts ranging from 20% to 40%. With low reservoir pressure, quick draw down capabilities, and shallow target depths, Yeso wells have a much shorter timeline required to reach pumped-off conditions and, therefore, provide insight on the early to mid-life performance.

INITIAL PRODUCTION

Yeso horizontals have been initially produced with various sizes of electric submersible pumps (ESPs) and long-stroke pumping units. ESPs have proven to be the best artificial lift mechanisms to recover completion fluids and achieve high initial oil and gas rates. In 2013, COG used both 1050 series ESPs and Rotaflex units for initial production. Both artificial lift methods were successful in drawing the wells down to pumped-off conditions, although the period needed to reach this inflow was at least 8 months. In Figure 2, cumulative production was plotted to illustrate that long-stroke units produced the same amount of oil as an ESP with the break-even point occurring at 244 days. Electrical power was not available during this period so monthly generator and fuel costs were as high as $40,000 per month to operate ESPs and $20,000 per month to operate Rotaflex units. In 2014, COG moved to using a larger 1750 series ESP that could produce up to 2200 BFPD, initially, and produce as low as 400 BFPD at the end of the duration. This design has proven to draw the well down within 6 months, on average, and reach initial oil rates of 450 BOPD or higher. Even with higher fuel and generator costs, the larger 1750 series ESP produced the best economics when considering production, the initial investment, monthly operating expenses, and converting from ESP to a rod pumping system. The results of economic analysis performed on each case of artificial lift are shown in Table 1. Utilizing a 1750 series ESP and converting to rod pump system equipped with a 640-365-144 unit provides the best rate of return and net present value while also reducing the monthly lease operating expenses by $10,300 in comparison to the other systems. Three factors can change the economic results: 1) Using company owned equipment out of inventory, 2) reservoir performance, and 3) time required to convert from ESP to beam pump.

GAS SEPARATION AND ROD PUMP CONVERSIONS

Data was gathered from the past two years of rod pumps in Yeso horizontal wells and compiled to compare successful and unsuccessful characteristics of the designs. Two key characteristics were identified in the process: The downhole pump capacities were exceeding separator capabilities and the maximum diameter of separator was not being employed. The industry standard for gas travel in liquid is 6" per second. Most gas separators use gravity and area to separate free gas from liquid. The following equation describes liquid velocity in a downhole gas separator:

$$V_{Liquid} = .0119\left(\frac{Pump\ Capacity,\ BFPD}{ID^2 - OD^2}\right)$$

Where:

$$V_{Liquid} \leq .5\ ft/sec$$

Various designs of separators were used, but the most effective version was found to be the basic modified "poor boy" design. Packer-type gas separators were effective, but presented challenges in wells where sour gas and paraffin are prevalent. Figure 3 shows a schematic representation of the modified poor boy design. In order to maximize flow rate, the area between the inner diameter of the separator and the outer diameter of the dip tube must be also maximized. Dip tube length can be determined by sizing the annular volume in the separator at least 50% greater than the volume of one single stroke of the sucker rod pump.

The majority of the Yeso horizontals wells drilled by COG are designed with 7" casing set at the kick-off point where it then reduces to 5.5" casing throughout the remainder of the well. The largest outer diameter of a separator that can still be fished or washed over is 4.5". At flow rates of 560 BFPD, the dip tube diameter of 1.25" was chosen as no fluid friction or restriction was observed. It is critical to use the inner diameter of the separator which is 4" and the outer diameter of the dip tube which is 1.66". After entering the measurements in the equation and using a 24 hour flow rate of 560 BFPD, the velocity of the liquid is found to be 0.503 feet per second. After assuming inefficiencies due to slippage, the liquid velocity will be less than 0.5 feet per second.

The preferred surface design is a 320-360-288 Rotaflex equipped with a variable speed drive (VSD) to help with sudden changes in pump intake pressure or pump fillage when approaching pumped off conditions. Many Yeso horizontals experience erratic conditions due to slugging effects. The VSD is essential in keeping steady runtimes while conditions in the wellbore are constantly changing. The Rotaflex unit has wide range of production capabilities without changing downhole design and also performs efficiently throughout the duration of its usage. Figure 4 shows a production plot using this specific design from onset production to present time. Converting from a 1750 series ESP to a Rotaflex unit does not have favorable economics in comparison to converting to a 640-365-144 pumping unit, but the design has been effective in every conversion.

The conversion from an ESP to a 640-365-144 pumping unit has also proven to be effective. The initial investment of the conventional pumping unit is 60% less than the Rotaflex unit. This component alone makes the case of converting to a 640-365-144 pumping unit the most lucrative. There are only two disadvantages to this system: 1) The downhole and surface design do not have the same producing range of the Rotaflex without making changes downhole and 2) the conventional unit can have as many as five times more cycles on the downhole equipment. In Table 2, the performance of each system is outlined. The 640-365-144 unit must be designed with a fiberglass rod and steel string. When slowing the 640 down to 5.5 SPM and changing the surface stroke to 82.9 inches, under travel will occur in the downhole stroke causing increased upper buckling tendency and rod coupling wear. Downsizing the pump diameter at the right time can be made to meet inflow performance and eliminate under travel issues.

PRODUCING YESO HORIZONTALS IN THE CURVE

Producing bottomhole pressures of Yeso horizontal wells have reached as low as 250 psi while static bottomhole pressures may not exceed 300 psi during build-ups. When producing 550 feet (TVD) above the lateral at the KOP, poor inflow performance results in rapid declines of oil and gas. In order to decrease the hydrostatic head on the formation and enhance influx, the pump intake must be lowered into the curve. COG has lowered 25 wells to produce at 45 degrees deviation. These production results are illustrated in Figure 5 as the cumulative production of every well is normalized to time zero when the well was lowered into the curve. Every well has shown to mitigate cuts in reserves and in select low pressure applications has shown to accelerate reserves. (Two wells did not meet economic criteria with frequent failures and were raised back to the KOP to continue producing.) Figure 6 shows the total daily production of 17 wells that have been producing for at least 200 days after being lowered. The observed steep decline prior to the workover has been arrested and rates appear to stabilize at 600 BOPD, cumulatively. Figure 7 depicts the performance of the same 17 wells by plotting the cumulative production of all wells from 100 days prior and 200 days after being lowered into the curve.

With the casing diameter now being reduced to 5.5", the maximum diameter of the separator that can be installed is 3.5" with slimhole collars. The 3.5" separator equipped with a 1" dip tube can produce 290 BFPD without experiencing any signs of gas interference. The pump and surface equipment can then be properly sized to achieve 290 BFPD in a 24 hour period. The rod design popularly used includes the use of an all steel string and sinker bars from the KOP down to 45 degrees at the seat nipple. (The sinker bars provide ample girth to minimize the downhole stress while the low profile couplings mitigate the rod to tubing wear.) With the separator being placed at 45 degrees, gravity can still effectively separate free gas from the wellbore fluid. Gas separators are also considered to perform better when resting one side of the wellbore.

In an eighteen month period, 16 failures have occurred resulting in a current failure rate of 0.44 fwy. Most of the failures occurred from the pump wearing against the barrel. Estimating a conservative cumulative repair cost of $400M and considering 200 BOPD in uplift, the economics yield a net present value of $6.7MM and a 2 month payout using a current commodity price of $52 per barrel. The failure rate is approximately twice that of Yeso vertical wells, but proves to be profitable while also consistently producing as the model describes.

CONCLUSIONS

- The best economic results were achieved utilizing a 1750 series ESP from onset production to six months where the well should then be ready to convert to a rod pumping system using a 640-365-144 unit.
- Rotaflex units are effective, but are not as economically favorable due to the large initial investment.
- Larger wellbore diameters allow more fluid to be produced through a modified poor boy separator without seeing signs of gas interference.
- All rod pump designs in horizontal wellbores must begin with satisfying the liquid velocity equation.
- Pumping wells in the curve can maintain and, in some cases, increase production.
- Production rates observed after lowering wells into the curve are enough to justify a higher failure rate and increase in operating expenses.
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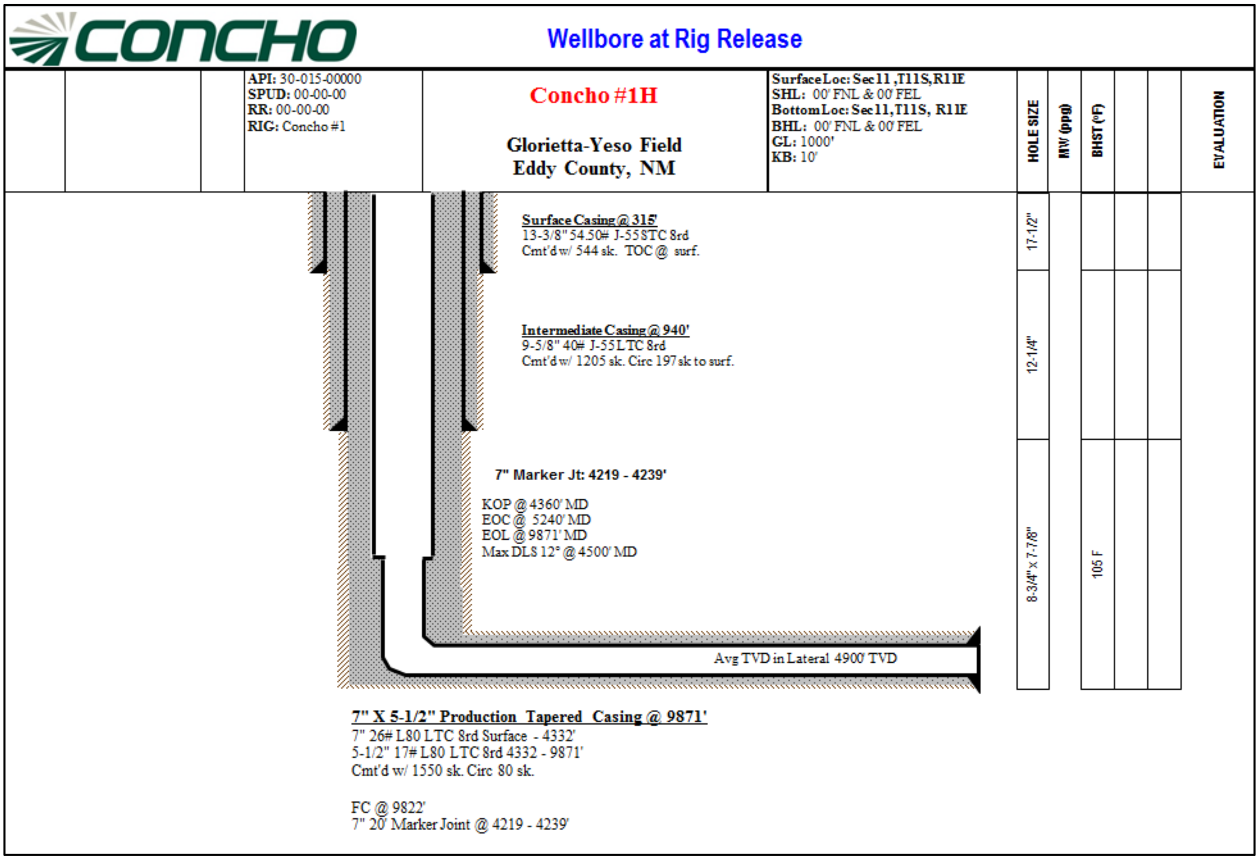

Figure 1 - Yeso Wellbore Diagram

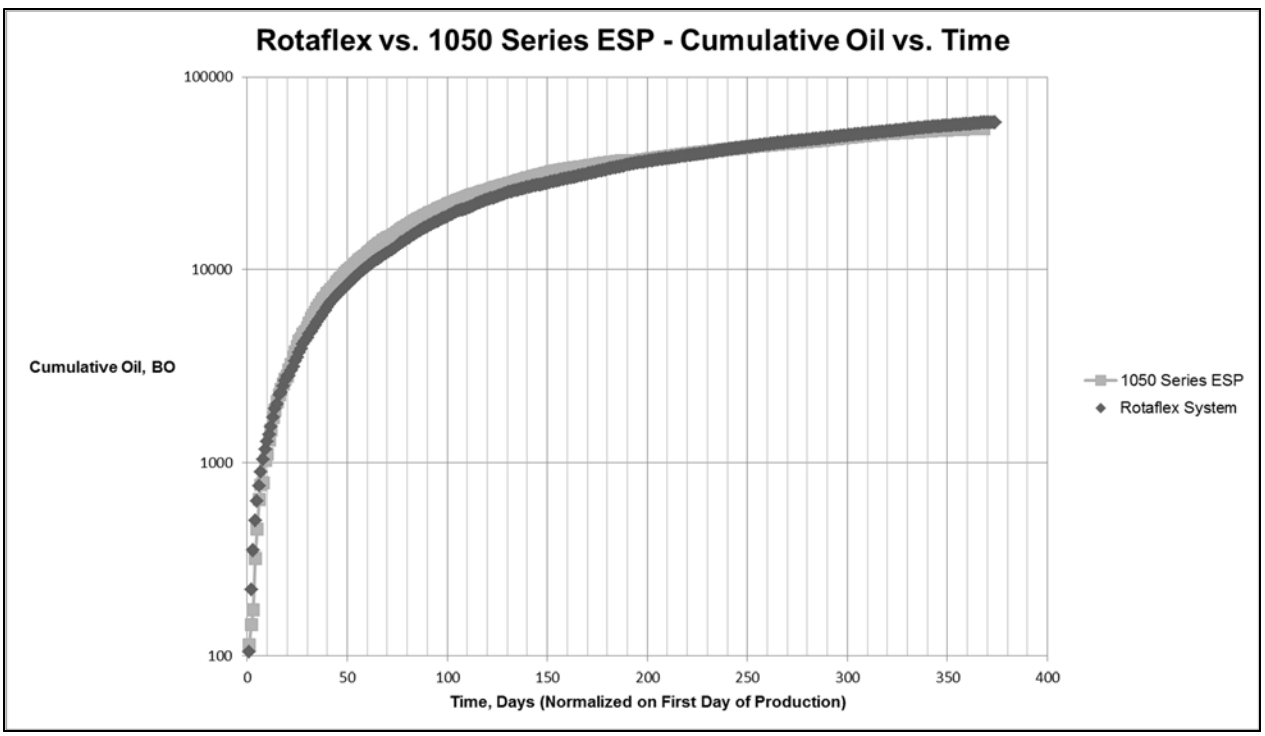

Figure 2 - Rotaflex vs. 1050 Series ESP (Cumulative Oil)

Aries Case Description	INITIAL IP BOPD	INITIAL IP MCFPD	6 Month BOPD	Capital Incr, M$	Incr 6 Mos LOE, M$/mo	Undisc Payout, yrs	Undisc ROI	ROR, %	PV 10%, M$
1 ESP 1050 to Rods	300	390	120	215	36.8	2.52	3.53	35.36%	$3,184.1
2 Rotaflex to Life	225	293	120	248	12.0	2.56	3.55	34.73%	$3,206.4
3 ESP 1750 to 640 Unit	450	585	120	261	26.5	2.19	3.51	40.87%	$3,438.5
4 ESP 1750 to Rotaflex	450	585	120	398	26.5	2.33	3.39	38.23%	$3,304.7

Table 1 - Initial Production Economic Analysis

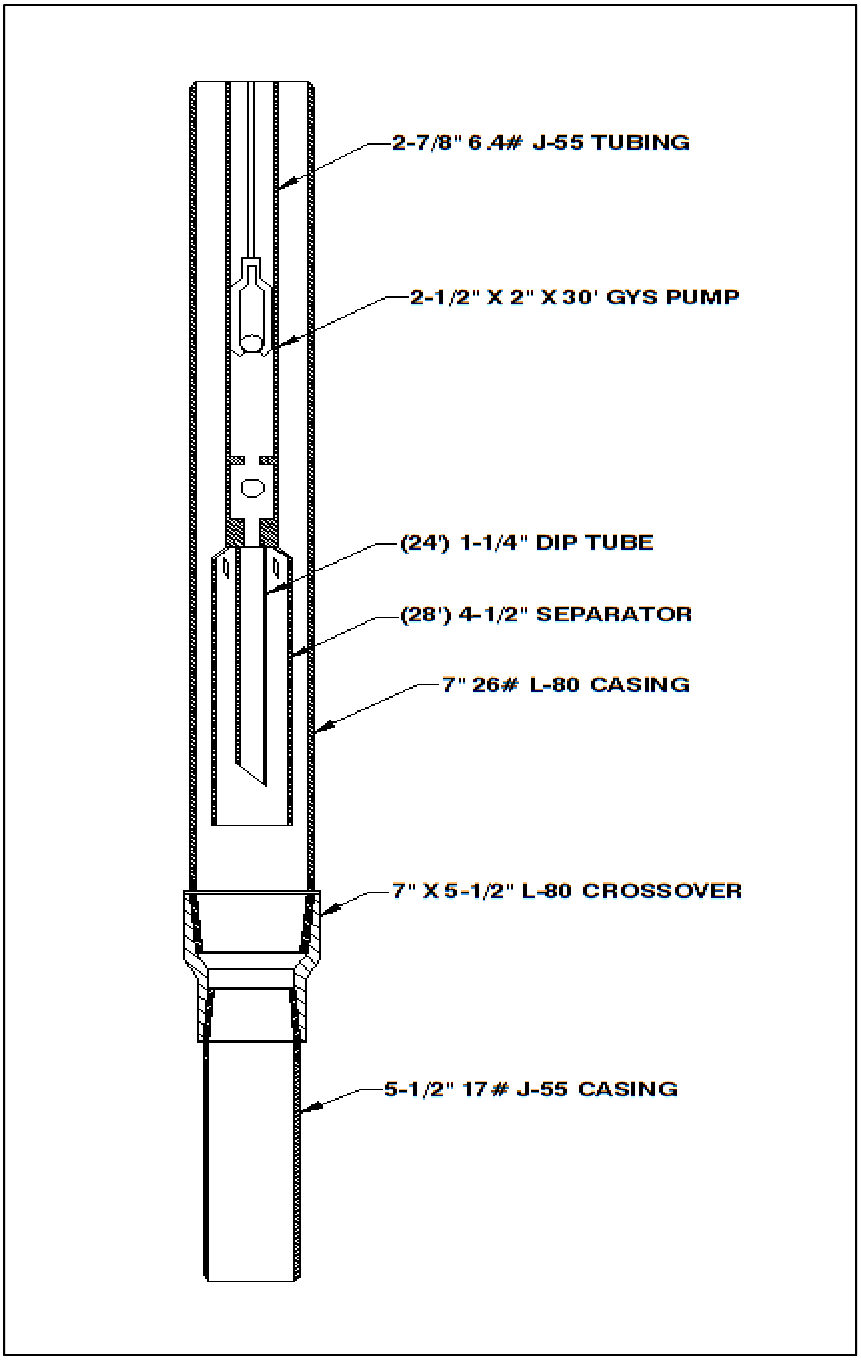

Figure 3 – 4.5” Modified Poor Boy Separator

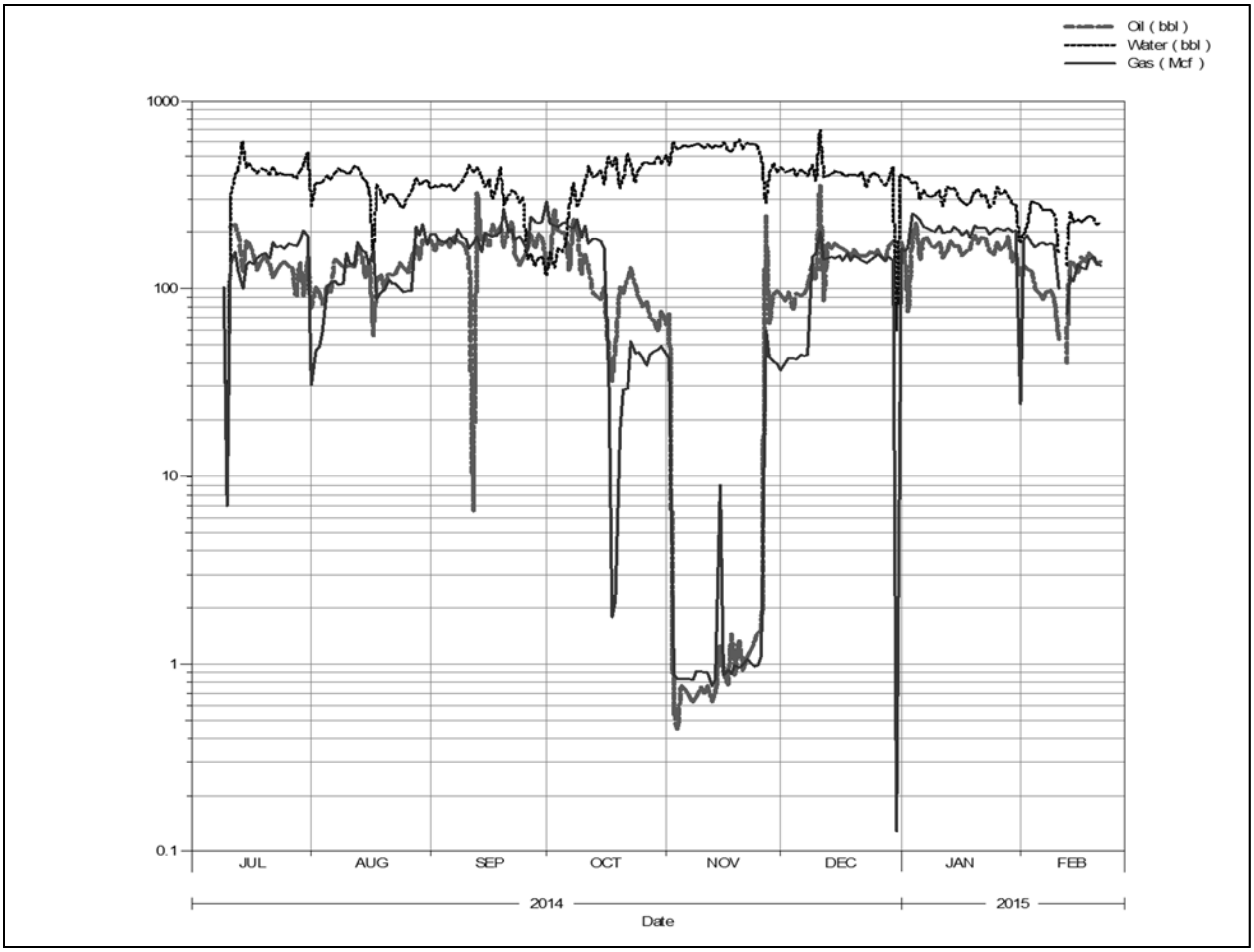

Figure 4 - Production Obtained Using a Rotaflex Unit

Pumping Unit	Speed, SPM	Pump Diameter, inches	Stroke Length, inches	Capacity, BFPD	Cycles Per Day
Rotaflex	4.16	2	288	560	5991
	1	2	288	134	1440
640-365-144	8.4	2	144	564	12096
	5.5	2	82.9	212	7920

Table 2 - Capacity and Cycles of Artificial Lift Design

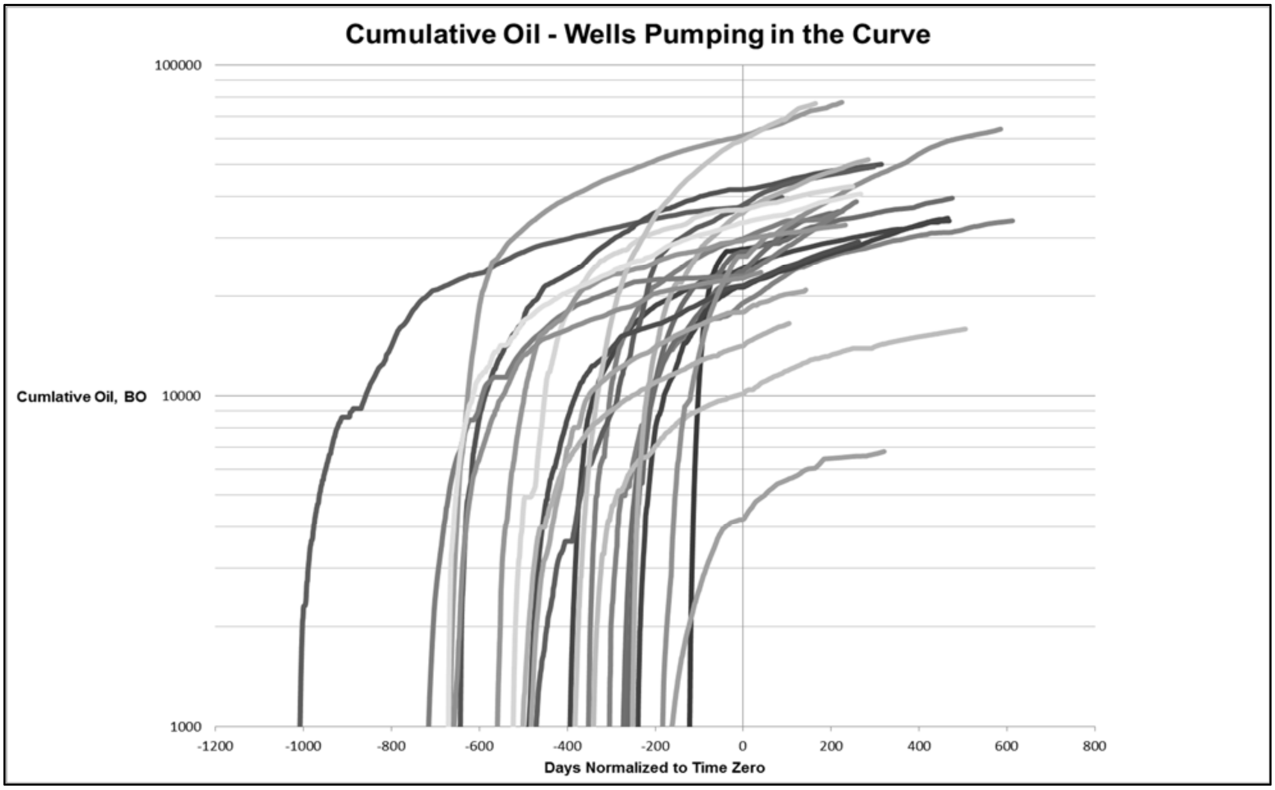

Figure 5 - Cumulative Production of Wells Producing in the Curve.

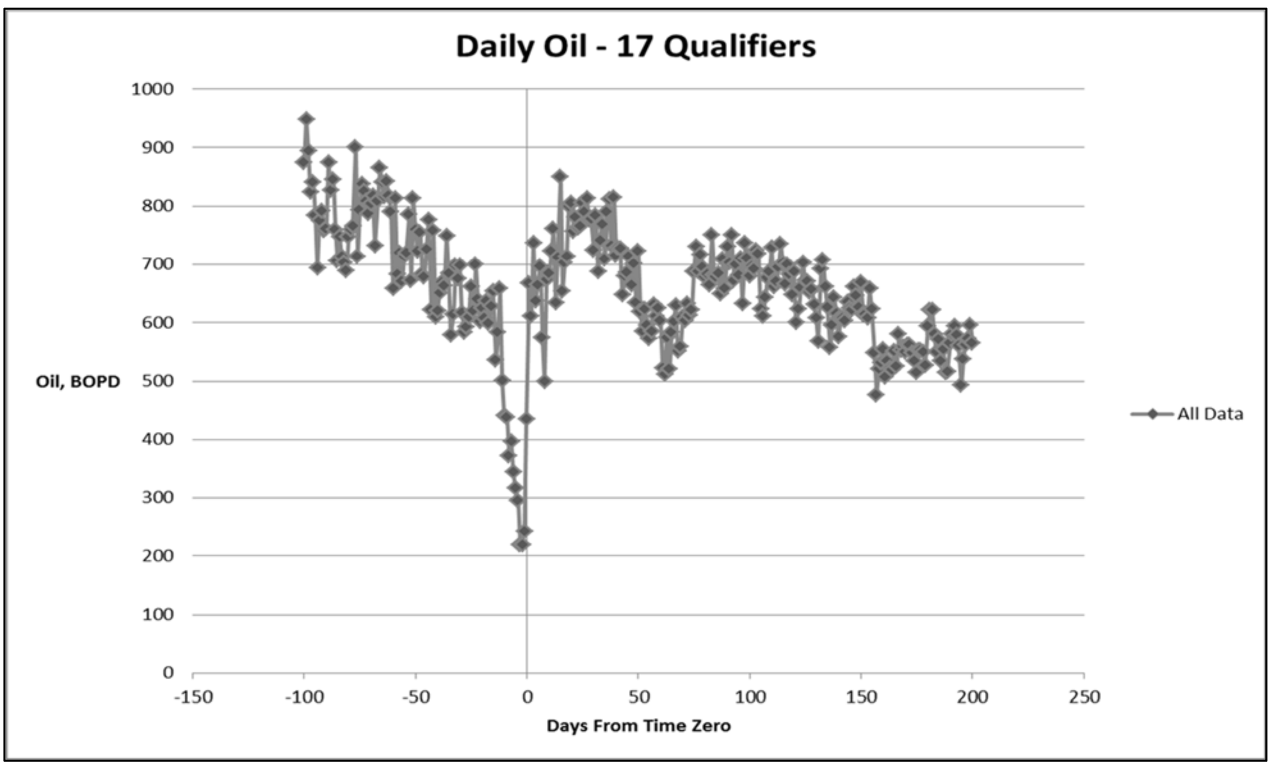

Figure 6 - Combined Daily Production of 17 Wells Lowered

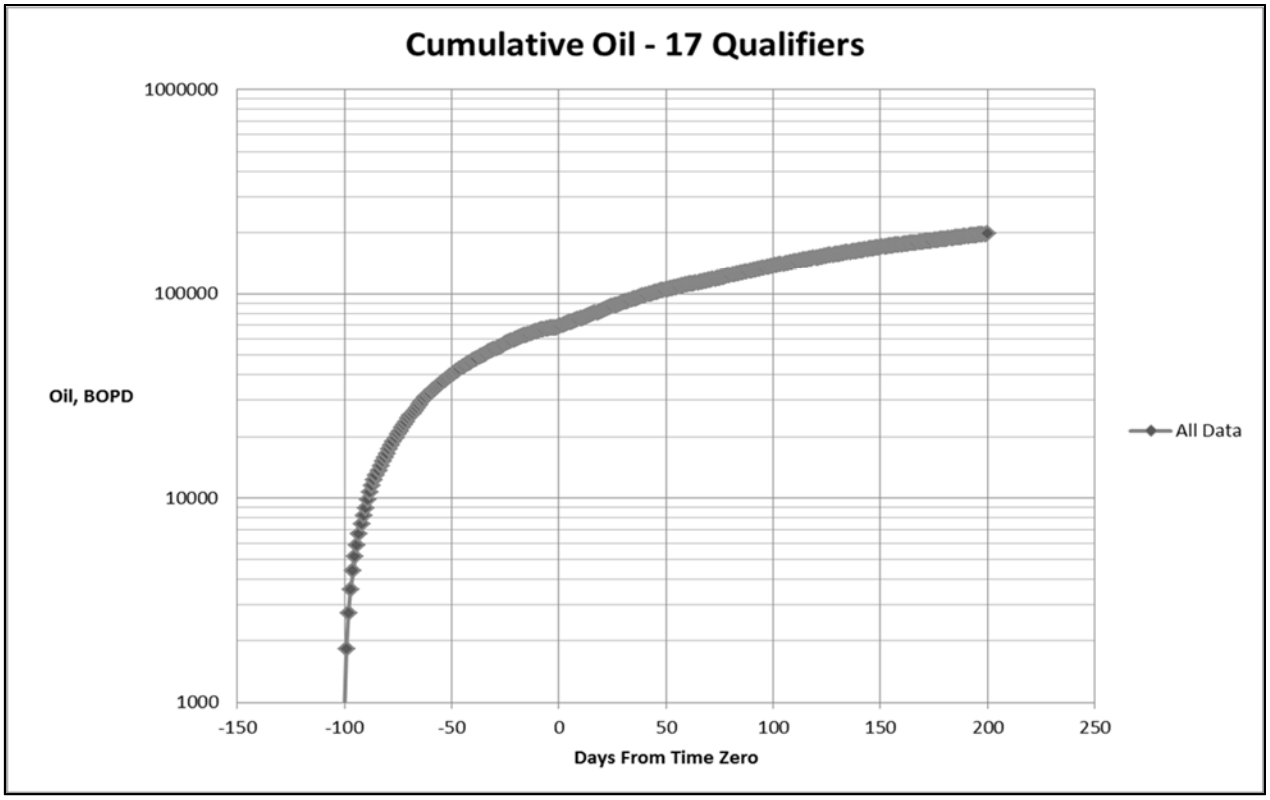

Figure 7 - Cumulative Oil of 17 Wells Combined.