RECIPROCATING ROD LIFT OFFERS ALTERNATIVE METHOD OF HIGH-VOLUME LIFT IN BAKKEN WELLS

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ABSTRACT

Contemporary lift strategy for a newly completed well typically includes a period of unassisted flow followed by an Electrical Submersible Pump (ESP) system. This is followed by one of a multitude of artificial lift options often culminating in a rod lift strategy for low production to end of life. Among the primary drivers of lift type selection is maximum uplift capability – an area in which rod lift has seen significant investment and improvement over time.

This paper will seek to submit for consideration an alternative strategy for high-volume artificial lift made possible by recent improvements to what has historically been a popular, albeit marginal, lift type: reciprocating rod lift.

INTRODUCTION

More than 90% of all producing oil wells will require some form of artificial lift[1]. As of 2016, there were an estimated 600,000 producing wells in the world utilizing some variation of reciprocating rod lift[2]. The general function and science have been around for over a century and, at their root, remain largely unchanged today[2]. A system of (typically) 2 valve assemblies alternate opening and closing to generate pressure differentials that allow production fluids to pass through a compression chamber and ultimately be lifted to surface at reservoir pressures significantly lower than would be required for the same fluids to flow under their own power. The operative components are the valve assemblies inside the pump while the larger system consists of a string of sucker rods and any of several downhole tools that serve to actuate the pump using motion generated by the surface equipment. Mechanically, the system is relatively simple; the sheer quantity and variety of equipment involved does, however, provide ample opportunities for improvement.

By contrast, an ESP is essentially a series of downhole centrifugal pumps driven by a submersible motor that serve to generate enough fluid pressure to allow production fluids to flow to surface[1]. The uplift capacity of a properly-designed and efficiently-operated ESP system is upwards of 30,000 BFPD – unrivaled by rod lift and other mechanical forms of lift[1]. Understandably, many North American operators elect to utilize ESP systems for initial production down to a production range of 250-350 BFPD at which point an alternative lift system may become more economical. Increasingly operators are evaluating the economics of a rod lift transition at higher production rates particularly in applications experiencing high ESP failure rates, where power consumption or availability is a concern, or where gas compression infrastructure is either not available or uneconomical to support a gas lift system. It is the intent of the data presented in this paper to further support the idea that high-volume reciprocating rod lift systems, when properly designed and operated, are capable of handling a transition from ESP without significant production loss in the 450-700 BFPD production range – potentially replacing a late-run or low-rate ESP system.

IMPROVEMENTS

Various components including the pumping unit, sucker rods and downhole pump can all place severe limitations on the achievable uplift when producing a well with rod lift. The advancement of older products, in addition to the emergence of new products, has enabled the industry to redefine the production capabilities of rod lift as a form of artificial lift.

Pumping Units

The introduction of long-stroke pumping units with optimizations to the gear reducer, structure rating, and stroke length have facilitated efforts to increase production. With gear reducer ratings as high as 500,000 in-lbs and structure ratings as high as 60,000lbs, these units are equipped to better handle highly loaded wells (see Table 1). The longer stroke length translates to a slow pump stroke, providing more time for fluids to enter the pump intake which ultimately increases pump fillage and lifting efficiency. These features together make long-stroke units ideal for efficient pumping in deep, high-volume wells.

Sucker Rods

Exploration and production (E&P) in deeper/higher volume wells have required manufacturers to develop higher tensile strength rods in order to assist with the higher loading conditions. Changes to metallurgical composition and enhancements to manufacturing processes (forging, threading, shot peening, induction case hardening, normalizing/quenching and tempering, etc.) have aided in increasing the tensile strength (see Table 2). These high strength and ultra-high strength rods have a higher maximum allowable stress meaning they are less likely to permanently deform or fractured in a heavily loaded well.

Continuous Rod

Unlike conventional sucker rods, which are coupled every 25 or 30 ft (7.6 or 9.1 m), continuous rod requires couplings only at the top and bottom of the rod string, regardless of well depth. These rod strings are lighter than conventional rod strings since they do not require the use of guides or couplings. These lighter rod strings can be used as an alternative to conventional sucker rods when the unit, gearbox or rods are too heavily loaded. Additionally, continuous rod is a superior option in highly deviated wells because the uniform body design evenly distributes contact loads over the entire rod, reducing the severity of tubing and rod wear.

Pumps

The downhole pump is a major factor when considering the production capabilities of a rod lift system. In order to maximize the production, it is often necessary to use larger pumps such as tubing pumps and oversized tubing pumps. Provided in Table 4 is a chart which shows the changes in production, structure loading and gear reducer load as pump size is increased. The constants that were assumed for these scenarios have also been listed in Table 3.

FIELD RESULTS

Operator A

Operator A in the Bakken elected to transition to high-volume rod lift immediately after flowback on a series of wells. These wells shared similar characteristics in terms of their deviation, depth, and production targets. All of the wells listed below had pump depths between 8,500' – 9,000' MD and utilized a 306" long-stroke pumping unit with ultra-high strength sucker rods. Rod guiding locations and practices varied slightly between them, but the effects are assumed to be negligible for the purposes of this paper.

Well 1

Operator A was able to achieve daily production volumes averaging 775 BFPD over a 7-month period with the most productive of those months yielding a 921 BFPD average daily uplift (see Figure 1).

Well 2

Operator A was able to achieve daily production volumes averaging 767 BFPD over a 7-month period with the most productive of those months yielding an 898 BFPD average daily uplift (see Figure 2).

Well 3

Operator A was able to achieve daily production volumes averaging 844 BFPD over a 7-month period with the most productive of those months yielding a 1007 BFPD average daily uplift – which the operator achieved twice (see Figure 3).

Well 4

Operator A was able to achieve daily production volumes averaging 719 BFPD over a 7-month period with the most productive of those months yielding a 914 BFPD average daily uplift (see Figure 4).

<u>Operator B</u>

Operator B in the Bakken utilized a more conventional lift strategy by running ESP's initially but transitioning to rod lift sooner than they normally might. Their rod lift system consisted of a 366" long-stroke pumping unit with a 60,000-pound structure rating, high-strength sucker rods in 3.5" tubing, and a 2.25" pump.

The deviation profile of the well indicates that it was not a particularly troublesome application for rod lift in terms of friction and mechanical wear (see Figure 5). Operator B landed their rod pump at 10,200' MD, avoiding the high dogleg severity area below (see Figure 6). For this reason, slick sucker rods were utilized in lieu of guided which further reduced the overall system loading by eliminating excess weight and frictional forces.

Operator B elected to run ESP for initial production. The first ESP run was highly productive, averaging 904 BFPD until it was either shut down or replaced for the downtime shown between October and November (see Figure 7). The "second" ESP run, identified by the second spike in production, averaged 665 BFPD until it was ultimately removed in favor of a high-volume rod lift system. After install, there was a period of relatively low production due to low operating speeds – presumably attributable to a lack of familiarity with the system or some other operational anomaly. When the system began operating at the intended capacity it averaged 416 BFPD of uplift with a maximum daily production of 627 barrels of fluid.

The rod lift system achieved this without approaching the mechanical limits of either the pumping unit or the sucker rods. Maximum recorded polished rod loading of 53,052 pounds leaves the pumping unit loaded to 88% of its rating. Given the low unit and rod loadings present, there is certainly opportunity for this operator to either upsize the downhole pump or increase the unit's operating speed to further optimize production. By utilizing a variable speed drive and adjusting the intra-stroke speed settings to maximize pumping speed, Operator B could theoretically have run this unit 17% faster than they elected to.

CONCLUSION

Reciprocating rod lift has proven to be capable of consistent production exceeding 500 BFPD. Conventional lift strategy may indicate that rod lift is a low-production lift method targeting 250-350 BFPD but increasingly operators in North America are proving that this is no longer necessarily the case.

In conclusion, while reciprocating rod lift is unlikely to ever be capable of the uplift capacity of a high-volume ESP, there is evidence to suggest that in certain applications it is capable of providing ample production to facilitate a transition from a low-rate ESP at volumes of 450-700 BFPD.

REFERENCES

1. Waters, George, and Diego Narvaez. “The Defining Series: ELECTRICAL Submersible Pumps.” *The Defining Series: Electrical Submersible Pumps | Schlumberger*, Oilfield Review, 2013, www.slb.com/resource-library/oilfield-review/defining-series/defining-esp.
2. Ayan, Cosan, and Chip Corbett. “The Defining Series: ROD Pump Systems.” *The Defining Series: Rod Pump Systems | Schlumberger*, Oilfield Review, 2016, www.slb.com/resource-library/oilfield-review/defining-series/defining-rod-pumps#:~:text=The%20most%20common%20form%20of%20artificial%20lift%20for,rod%20string%20and%20a%20downhole%20pump%20%28Figure%201%29.

Reducer (in-lb)	Structure (lbs)	Stroke Length (in)
228,000	26,500	236
250,000	30,000	288
350,000	36,000	288
350,000	50,000	306
350,000	50.000	366
500,000	60,000	366

Table 1 - Typical long-stroke pumping unit specifications. The advent of a 60,000-pound structure rating paired with a 500,000 in-pound torque rated gearbox makes rod lift a viable option in applications previously unavailable.

Description	Grade	Chemical Composition	Tensile Strength (1000 psi)
Mid Strength	API Grade DS	Ni-Cr-Mo	115/140
High Strength	API Grade HA/HS	Cr-Mo / Ni-Cr-Mo	140/155
Ultra-High Strength	API Grade HY	Cr-Mo	-

Table 2 – Typical sucker rod grades and tensile strengths.

Constants	
Pump Depth	9000’
Pump Intake Pressure	100 PSI (Pumped Off)
Tubing Size	3-1/2”
Pump Efficiency	80%
Pumping Unit	Long Stroke 500-600-366
Speed	4.7 SPM
Pump Friction	200lbs

Table 3 – Constants referenced for pump capacity exercise.

Pump Size (in)	Production (BPD)	Structure Load (%)	Gear Reducer Load (%)
1.25	266	51.9	44.2
1.5	378	55.1	42.1
1.75	495	58.8	41.3
2	616	65.6	45.9
2.25	745	73.2	57.5
2.5	919	89.8	70.7
2.75	1050	96.8	77.7

Table 4 – Increasing pump size and its correlation to production and equipment loading. Pumping unit structure rating of 60,000 pounds allows for larger bore pumps landed deeper in wellbores – removing a previously limiting factor on production capacity.

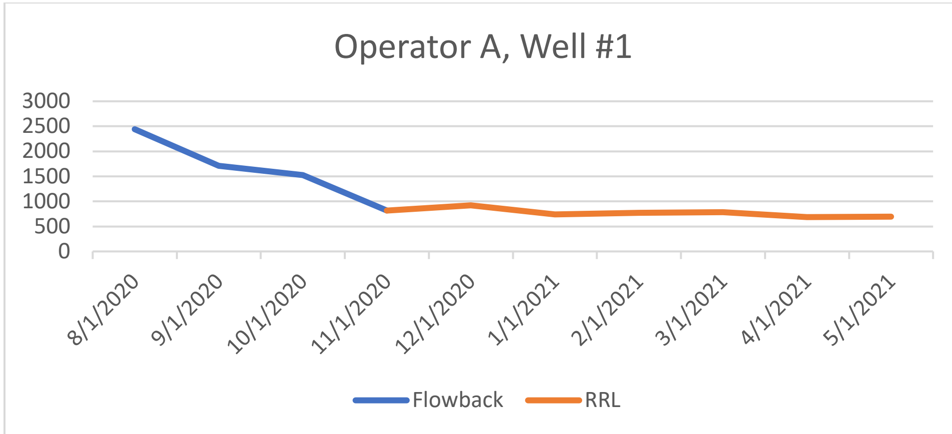

Figure 1: Initial production decline from flowback and transition directly to rod lift for Operator A in the Bakken. Sustained production of 675+ BFPD for all months recorded in this trial.

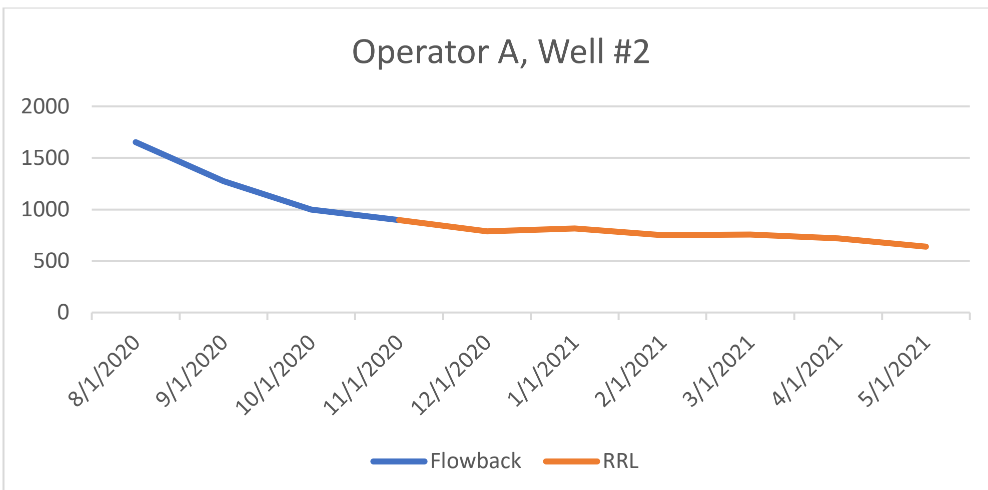

Figure 2: Initial production decline from flowback and transition directly to rod lift for Operator A in the Bakken. Sustained production of 600+ BFPD for all months recorded in this trial.

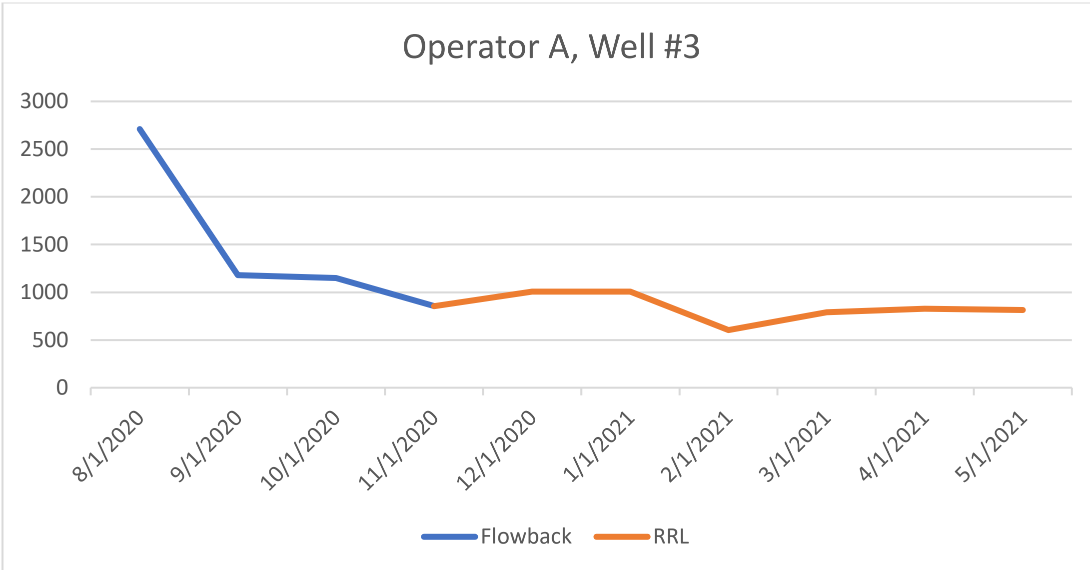

Figure 3: Steep production decline from flowback and transition directly to rod lift for Operator A in the Bakken. Sustained production of 600+ BFPD for all months recorded in this trial.

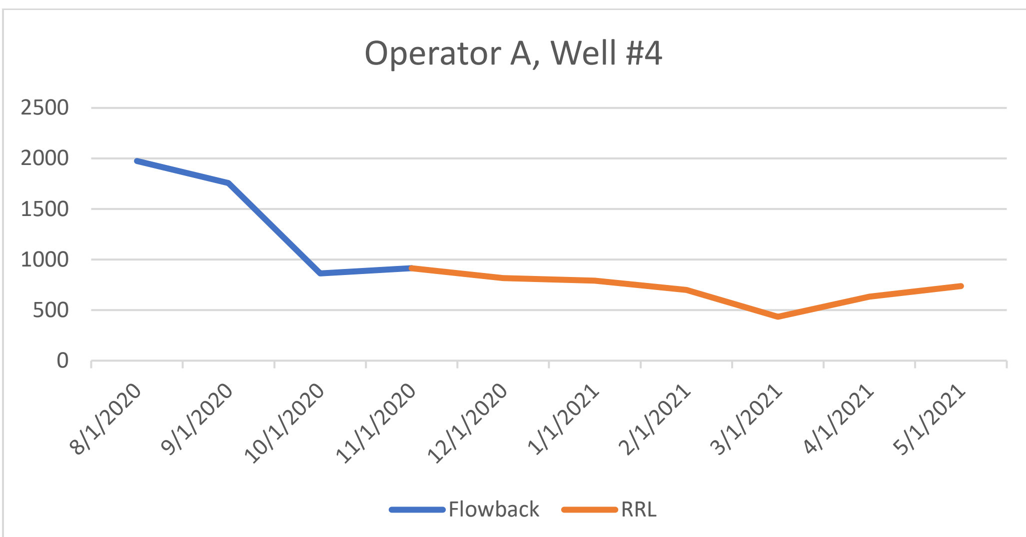

Figure 4: Steep production decline from initial flowback through transition to rod lift. Average daily production of 719 BFPD over a 7-month trial period while operating on rod lift.

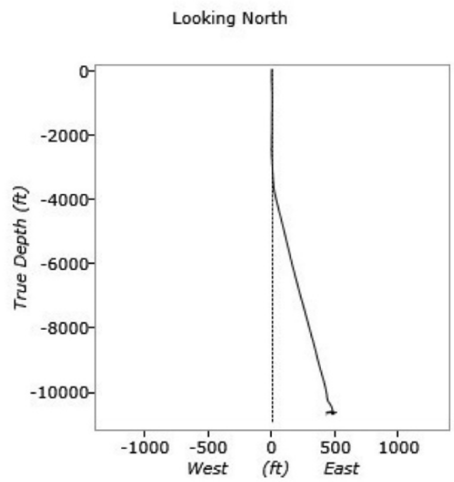

Figure 5: North-facing view of wellbore deviation for Operator B trial well in the Bakken.

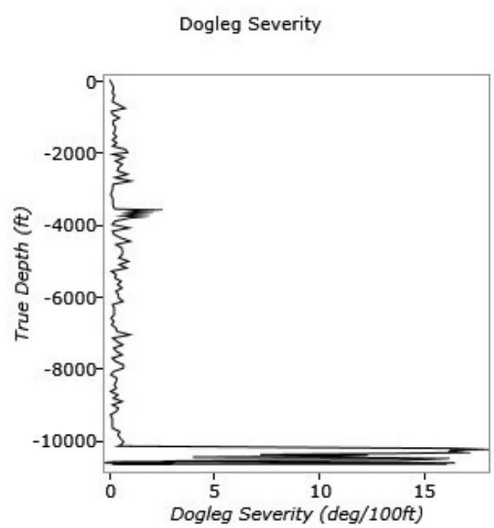

Figure 6: Plot of dogleg severity vs depth for Operator B trial well in the Bakken. Limited dogleg severity allowed the use of slick sucker rods in lieu of guided – providing substantially reduced rod and unit loading and allowing for a larger, deeper pump to maximize uplift potential.

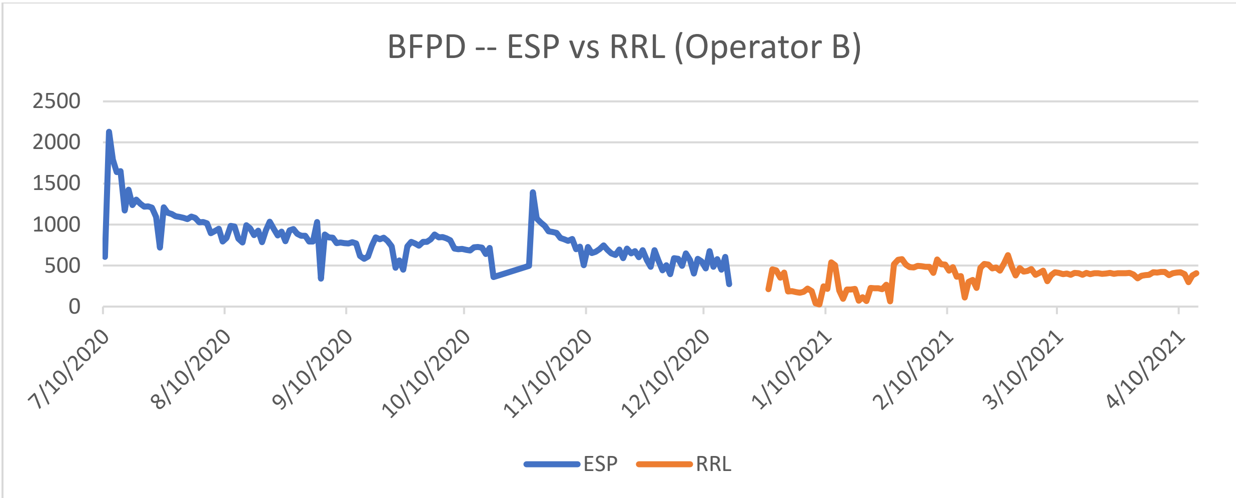

Figure 7: Production decline from ESP through rod lift transition for Operator B trial well in the Bakken. Initial rod lift installation yielded depressed production totals – presumably as a result of an operational anomaly. Beginning in February, rod lift system operated at intended capacity and averaged 400+ BFPD while maintaining <90% loading on pumping unit and sucker rods as well as <85% of maximum operating speed on unit.