HIGH LIQUID VOLUME PLUNGER LIFT PERFORMANCE IN THE PERMIAN BASIN

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ABSTRACT
This paper addresses the use of plunger lift in high liquid volume wells in the Permian Basin. This method of lift was first considered in an effort to transition high liquid volume wells from flowing to rod pump. Historically in the Permian Basin this was accomplished with high cost electric submersible pumps, gas lift or hydraulic lift. One of the criteria for success was that plunger lift would be able to economically maintain a well's production decline. Representative production plots are presented on the successful wells. This paper is an update of a previous paper presented in 2015 for wells in the Southern Delaware Basin.

BACKGROUND

As horizontal wells in the Permian Basin decline, some type of artificial lift is needed to continue to produce these wells. Because of the high flow rates associated with these wells the initial choices of artificial lift in the past have been electrical submersible pump (ESP), hydraulic lift, gas lift or rod pump. There are high costs associated with these types of artificial lift. Many operators have tried to move high volumes of fluid (more than 300 BFPD) with a beam pump, but the failure frequency has been high and thus was not an economic option. More recently operators have been testing a high liquid volume plunger lift system on these wells. The purpose of this paper is to determine the viability of plunger lift as a replacement for these other lift choices and if it can be viewed as the preferred intermediate step between flowing and beam pump and thereby avoid other, more costly forms of artificial lift. Can plunger lift be used to bridge the gap between flowing and rod pump? The answer to that question is twofold: First and most importantly, does the installation of a high liquid volume plunger lift system sacrifice production volumes relative to that of other lift choices? Secondly how do the lease operating expenses (LOE) of plunger lift compare to other options?

For the purpose of this paper we define high liquid volume plunger lift as wells having liquid volumes above 200 barrels of fluid per day(BFPD) and up to 600 BFPD. There have been instances of moving higher volumes than this, but in general these wells have not needed the assistance of artificial lift until liquid volumes fall below 700 BFPD. With true vertical depths (TVDs) around 10,000' on most of these wells they fall far outside of the "rule of thumb" range of GLR for plunger lift success, namely 0.4 MCF per barrel per 1000' of lift. The bottom hole pressures (BHP) for these wells are generally three times that of conventional plunger lift.

PRODUCTION DATA ANALYSIS

Table 1 shows representative production data (oil/water/gas), GOR, WOR and GLR up to the end of 2015. Figures 1-8 show representative production plots for some of the wells placed on plunger lift. Because the data comes from different operators there are differences in the software programs used, thus a variance in the format of the plots.

Table 1 shows a range of total liquid production from 269-602 BFPD and a range of gas production from 163-308 MCFD resulting in GLR's of 0.37-1.06. Plunger lift installed in wells averaging around 10,000 feet with GLR's this low is basically unheard of in the industry. We have concluded that the explanation for this is the unconventionally high bottom hole pressures (BHP) that range around three times the pressure required (100psi/1000ft) for conventional plunger lift.

Figures 1-5 are for wells that have been on plunger lift for all of 2015. Figures 6-8 are for wells that have been on plunger lift during the last 6 months of 2015. Wells 1-5 demonstrate that plunger lift has continued to produce in an acceptable production range and at times able to accommodate offset fracs resulting in spikes in water production. Wells 6 & 7 were flowing wells less than six months old that went directly to plunger lift after flowing back from frac jobs. Well #8 had previously been on ESP until 7/2015.

ESP PROS/CONS

The major benefit of an ESP is the ability to quickly draw down a well and thus increase initial production. In the Permian Basin we see the "flush production" benefit for the first few days after the pump comes on, but the increase in production quickly goes away and the well returns to its natural decline. As pointed out by Vogel (Refer-Figure 9), incremental production is difficult to achieve with incremental drawdown in a high reservoir pressure environment. Reservoir pressure in these wells is generally 3000# and higher. Unfortunately the average lifespan of an ESP in some areas of the Permian Basin is only a few months. This is due primarily to poor power quality, fluid composition (solids), and wellbore deviation. Another important note is the fact that when an ESP is run in the hole, the well has to be killed with brine water and production could be curtailed for up to a week waiting on rig and ESP vendor availability.

GAS LIFT PROS/CONS

The major benefit with gas lift is that there is nothing mechanical in the wellbore. This allows for the tolerance of solids in the production stream flowing back from huge frac jobs. Deviated wellbores are also not a concern. Issues with gas lift include long flow lines combined with high gas sales line pressures, compressor reliability, monthly operating expenses, available supply gas, lines freezing in winter and operator inexperience. Additionally, single well leases and undersized gas gathering systems pose unexpected challenges.

ROD PUMP PROS/CONS

The primary benefit with rod pump is that it is very effective when it is pumping properly. Field personnel are generally very familiar with this form of lift in the Permian Basin. Local expertise and support are also readily available. The problems are that rod pump has difficulty producing higher than around 300 BPD. There can be issues with the pump gas-locking in high bottom hole pressure wells. Solids in the flow stream coming back from frac jobs will damage the pump. It is difficult to properly size the pumping units to deal with the high initial decline rates of these type wells. Additionally, deviated wellbores will result in constant rod failure that escalate lease operating costs.

PLUNGER LIFT PROS/CONS

The major benefit of a plunger lift system is that it uses the reservoir energy to produce fluids and has a low overall operating expense associated with it. The entire system can be moved to a different well without a pulling unit and thus has a high salvage value. Chemical treatments to remove scale or paraffin are not necessary because of the plunger cycling up and down, keeping the tubing clean. The high liquid volume plungers that run in the Permian Basin are generally not conventional (solid), but tend to be" by-pass" plungers that allow for faster fall times to reach the plunger stop. This type of plunger allows a shut-in portion of the operational cycle that is shorter than a conventional plunger cycle, allowing for more production from the wellbore. A disadvantage to plunger lift is the amount of time it takes to adjust operating parameters to match reservoir inflow. Thus, it requires more oversight and field personnel with knowledge and experience to assure the success of operations.

PLUNGER LIFT COST COMPARISON

The average monthly operating costs per well for ESP, Gas Lift or Rod Pump in the Permian Basin can range from $10,000-$20,000 per month. The charges that make up these costs are equipment and installation, electrical consumption, monthly rentals, monitoring fees, workover rig time, pump repairs, etc. The average plunger lift related operating cost per well (including equipment) for the first year is less than $2,000 per month. Afterwards, the recurring monthly expense can be minimal to zero. Thus the incremental operating cost savings per well of plunger lift relative to other choices can be up to 90%.

PLUNGER LIFT OPERATIONS

Plunger lift systems are designed to operate on time or pressure settings depending on individual well behavior. Various types of plungers have been tested ranging from bypass to solid grooved depending on well conditions and behavior. It is important to properly prepare the tubing via slickline to make sure there are no obstructions that would keep the plunger from cycling the entire length of the tubing. Some wells have to be helped by swabbing to get the flow cycles started. Plungers will lose their seal efficiency over time and will need to be replaced. We have seen instances of production increases after replacing worn out plungers with fresh plungers after a period of time. All wells were put on automation allowing for remote monitoring and adjustments to flow cycles. The remote monitoring is a key element in maintaining flow cycles and not allowing wells to load up and stop flowing.

CONCLUSIONS

High liquid volume plunger lift can be installed and applied successfully on wells that meet certain GLR, WOR and reservoir pressure criteria. These installations of plunger lift systems have allowed operators to successfully bridge the gap between flowing and rod pump without any significant change to the decline curve shape and thus minimizing production curtailment. Plunger lift installations have also provided significant cost savings over other artificial lift choices.

REFERENCES

Ferguson, Paul, and Beauregard, E, "Will Plunger Lift Work in My Well?", *Southwestern Petroleum Short Course* (1983). Print.

Vogel, J. V. "Inflow Performance Relationships for Solution-Gas Drive Wells." *Journal of Petroleum Technology* (1968): 83-92. Print.

Smith, Ian, and Pafford, Terry, COG Operating, LLC, Swihart, M. C., PLSI, “High Liquid Volume Plunger Lift Performance in the Southern Delaware Basin”, *Southwestern Petroleum Short Course* (2015), Print.

Table 1: Plunger Lift Wells Production Data

Well #	*Oil*	*Water*	*Liquid*	*Gas*	*GOR*	*WOR*	*GLR*
	BOPD	BWPD	BFPD	MCFPD	MCF/BO	BW/BO	MCF/BBL
Well # 1	220	382	602	224	1.02	1.74	0.37
Well # 2	245	239	484	297	1.21	0.98	0.61
Well # 3	99	265	364	279	2.82	2.68	0.77
Well # 4	182	224	406	299	1.64	1.23	0.74
Well # 5	103	166	269	285	2.77	1.61	1.06
Well # 6	372	114	486	308	0.83	0.31	0.63
Well # 7	272	156	428	210	0.77	0.57	0.49
Well # 8	201	89	290	163	0.81	0.44	0.56

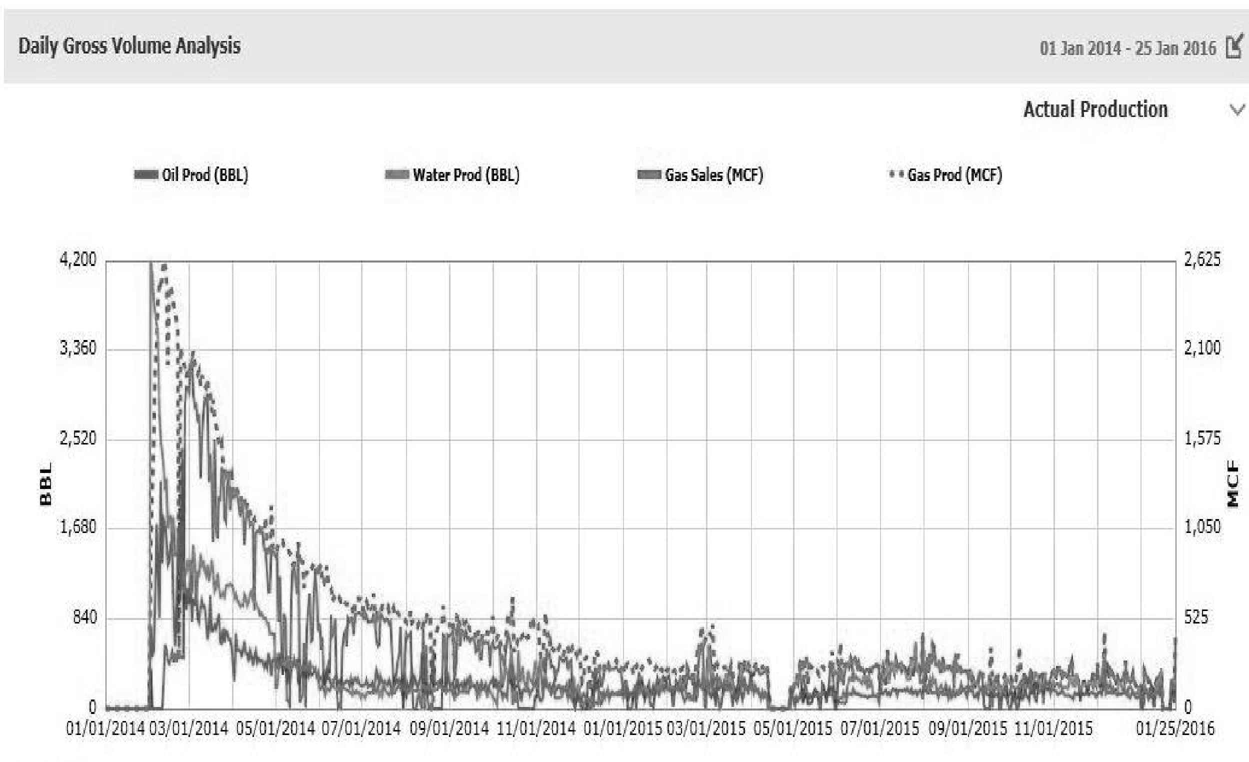

Figure 1 – Plunger Lift Well #1

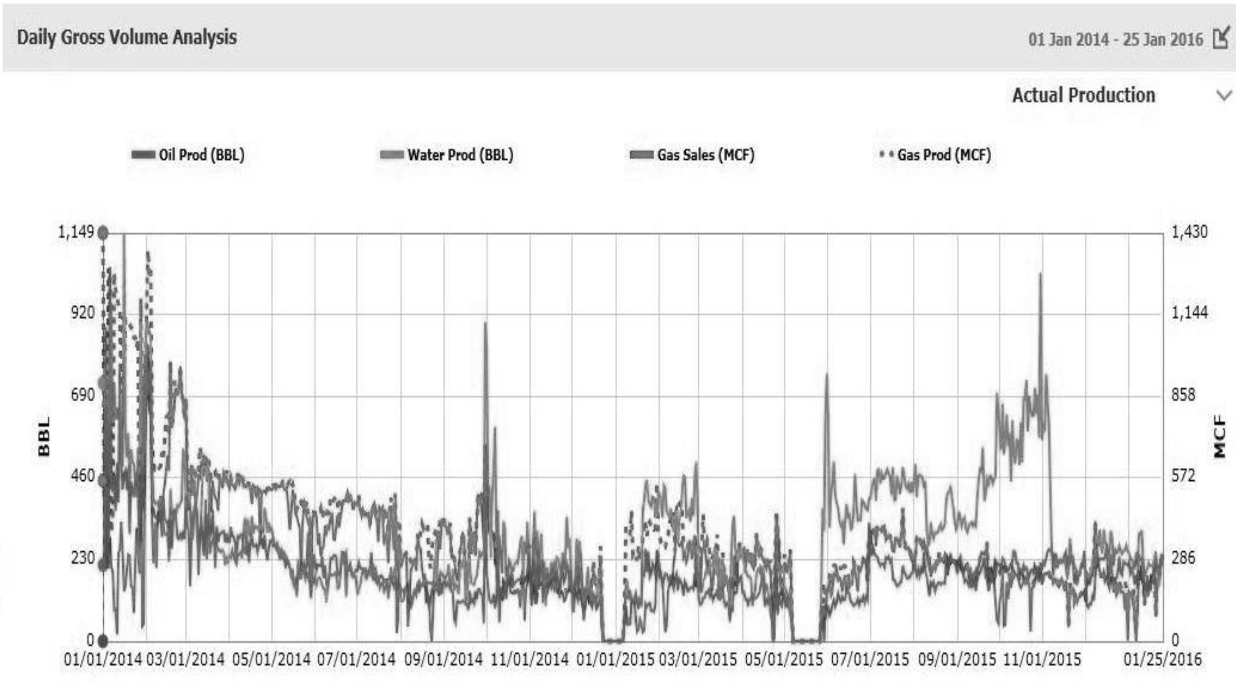

Figure 2 – Plunger Lift Well #2

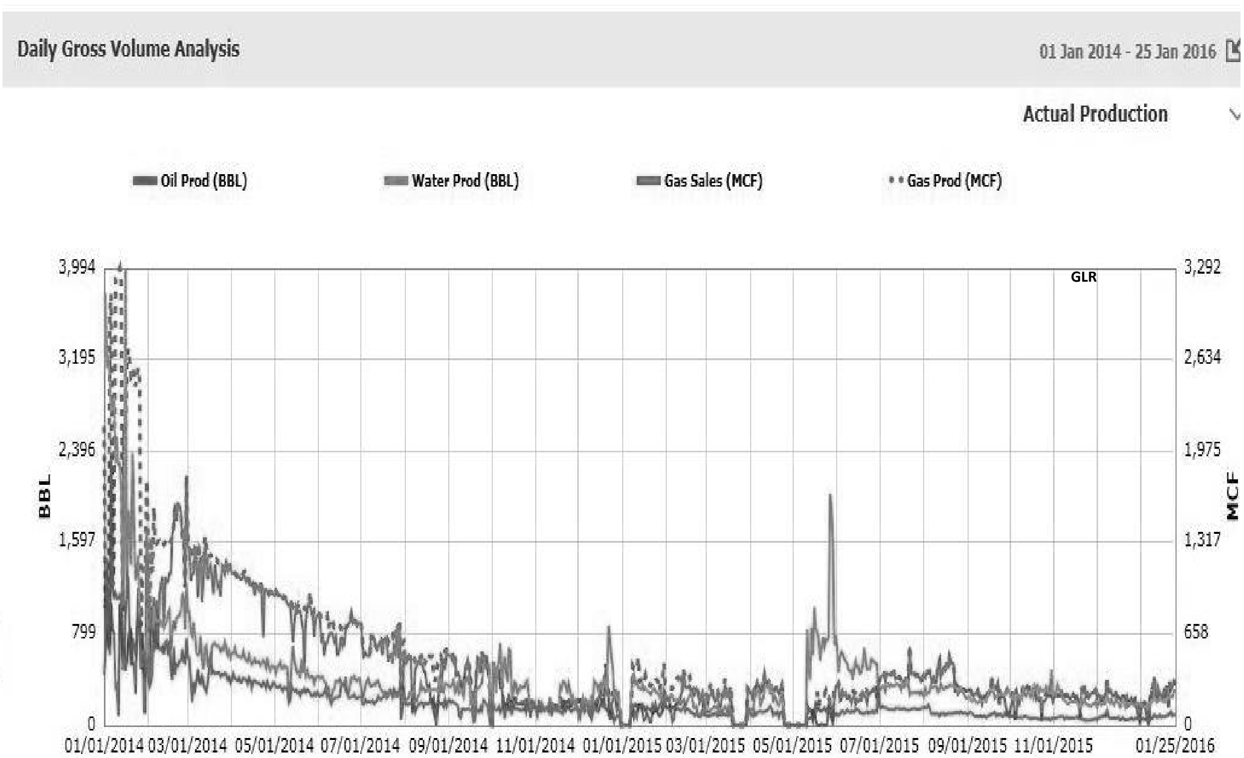

Figure 3 – Plunger Lift Well #3

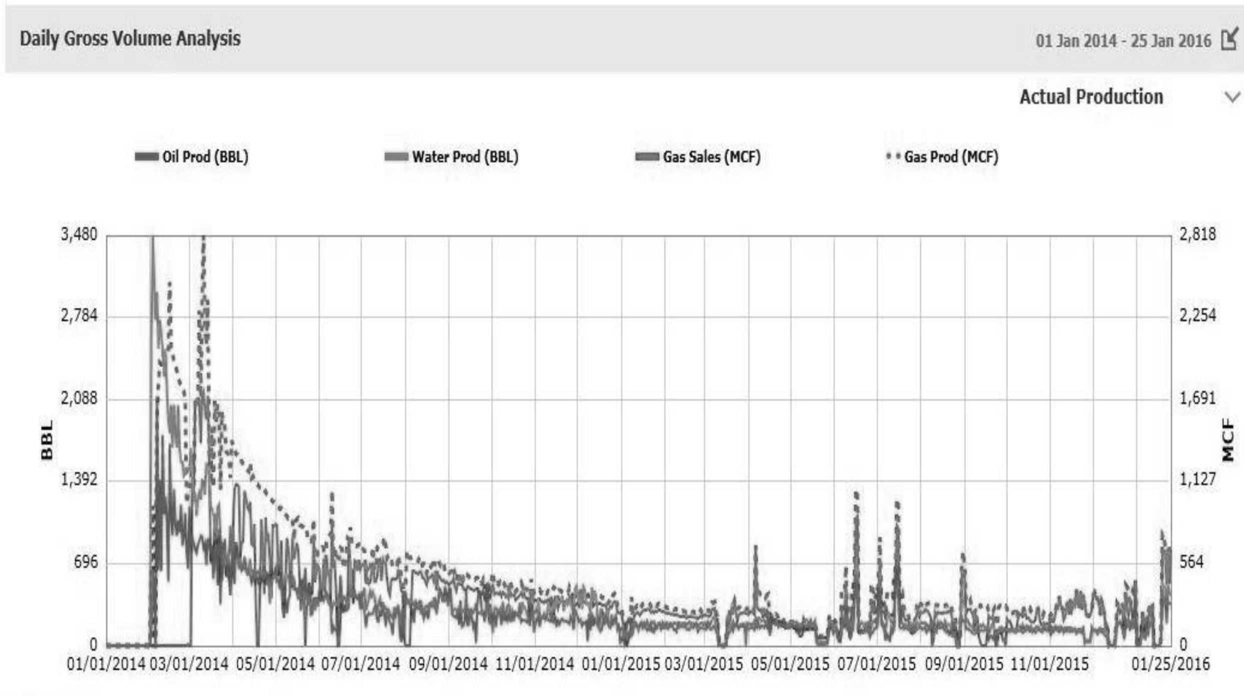

Figure 4 – Plunger Lift Well #4

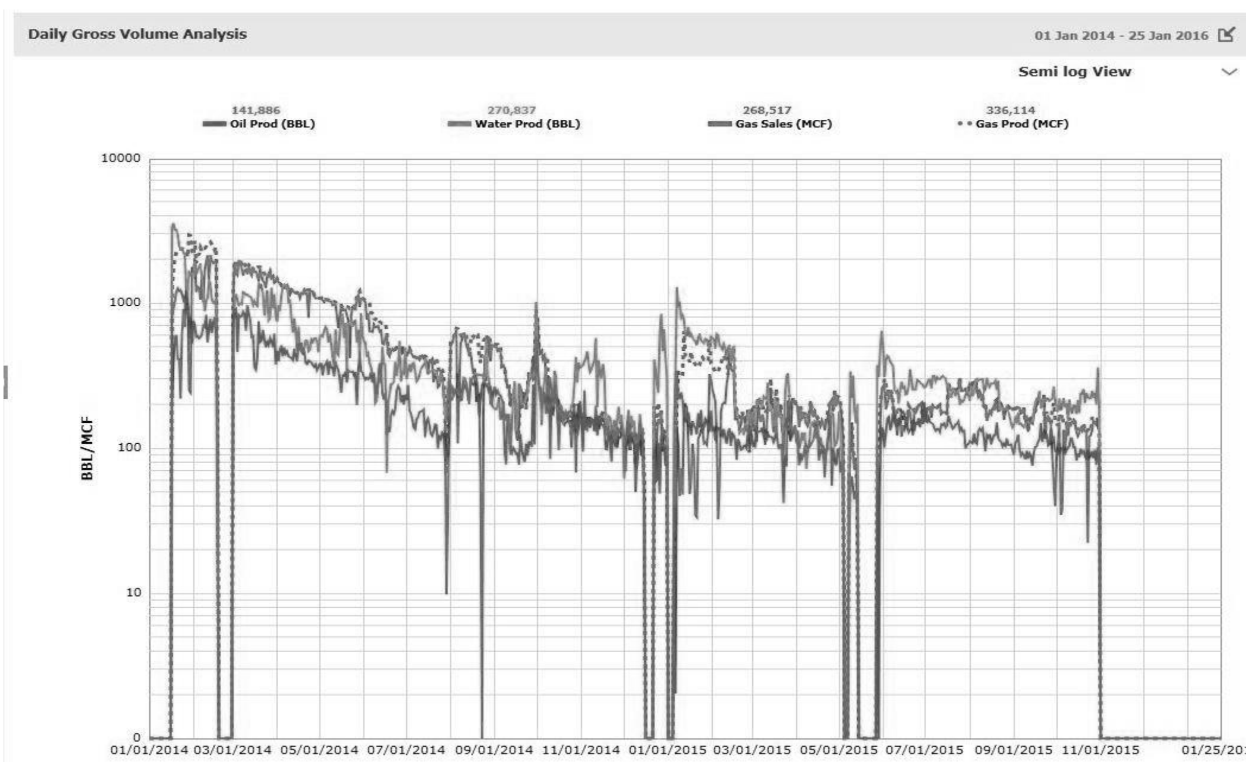

Figure 5 - Plunger Lift Well #5

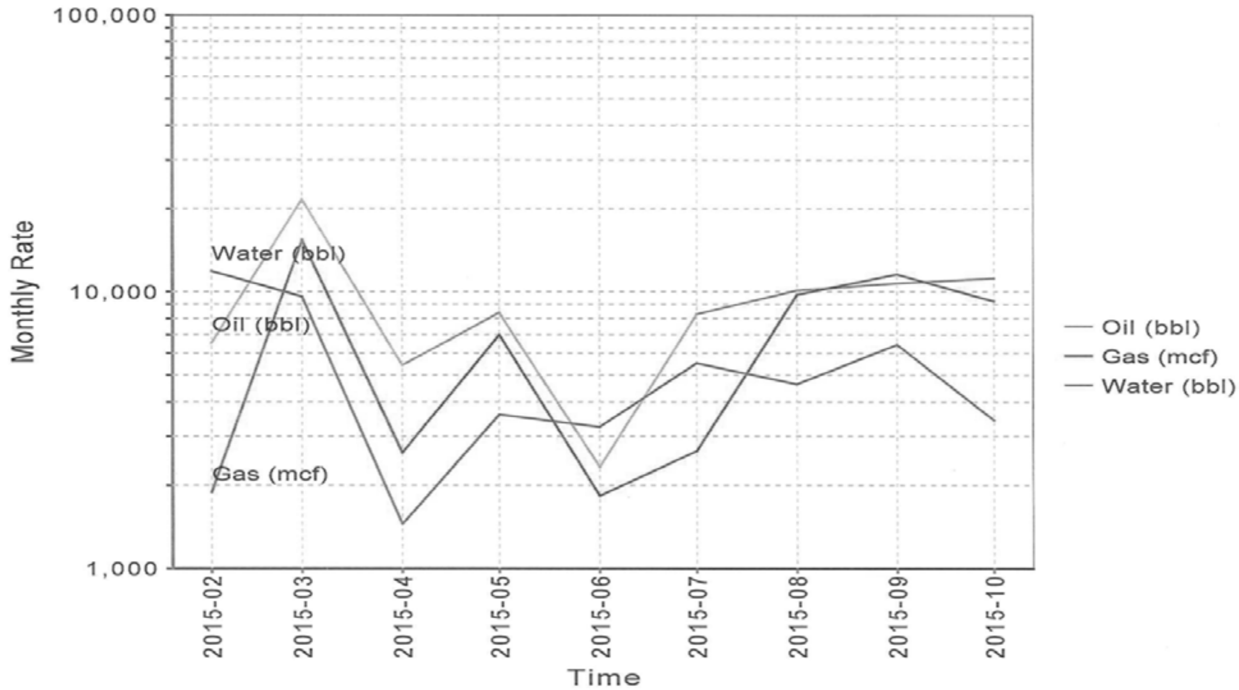

Figure 6 – Plunger Lift Well #6

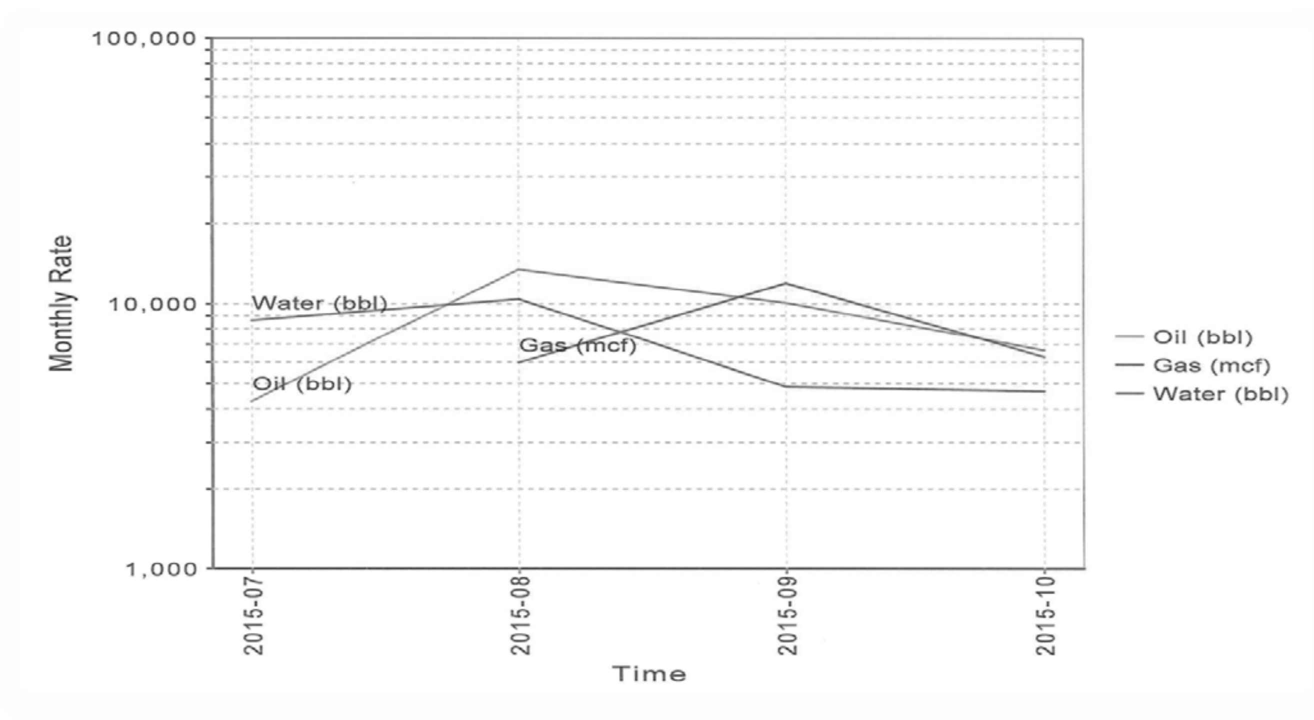

Figure 7 – Plunger Lift Well #7

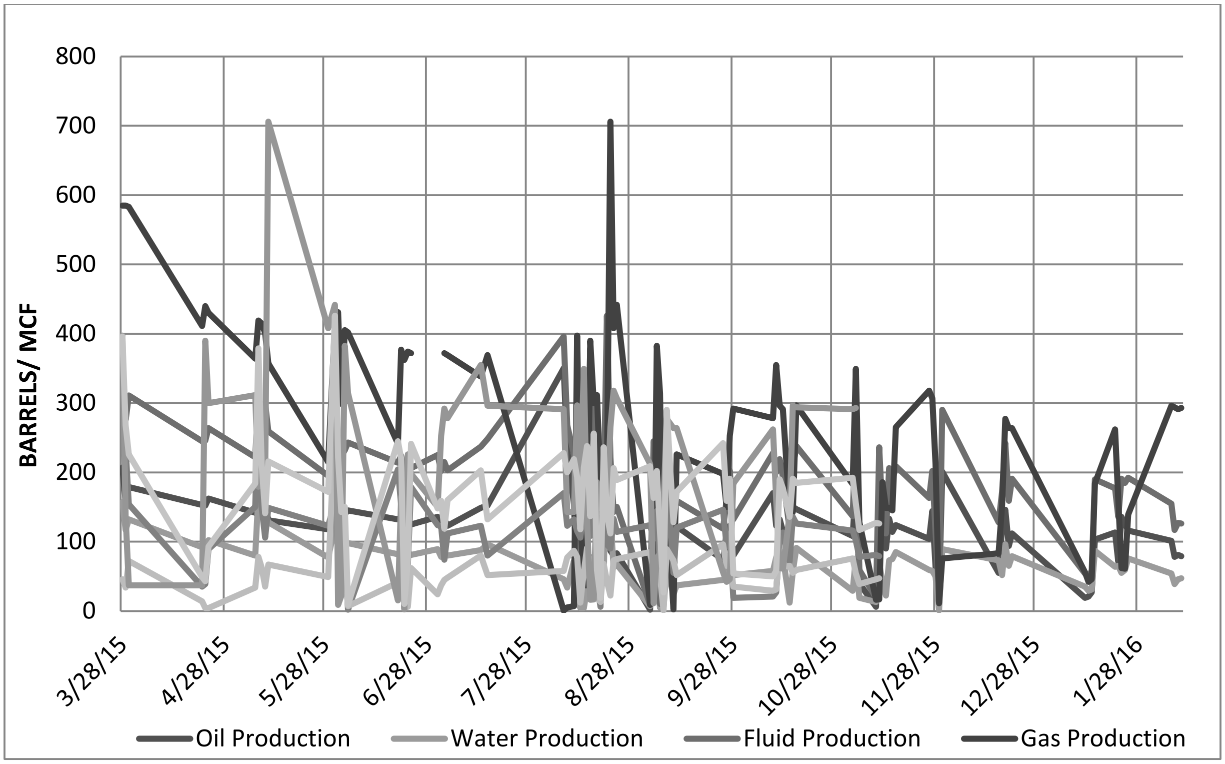

Figure 8 - -Plunger Lift Well #8

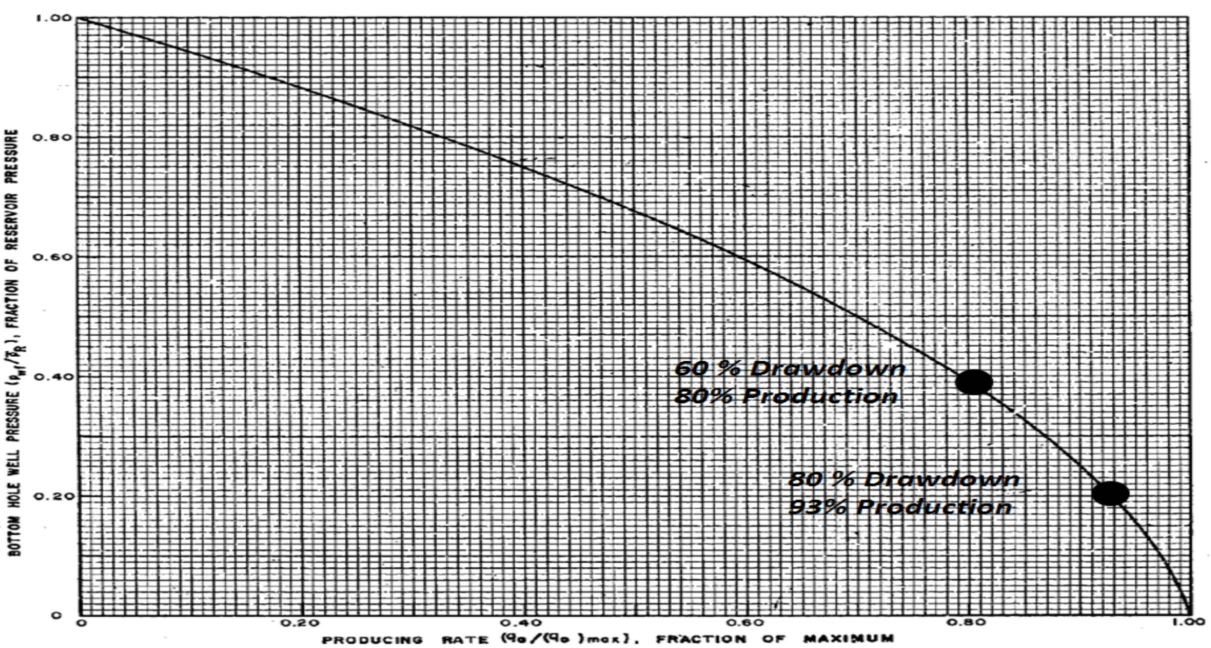

Figure 9: Inflow Performance Relationship for Solution-Gas Drive Reservoirs