HIGH LIQUID VOLUME PLUNGER LIFT PERFORMANCE IN THE SOUTHERN DELAWARE BASIN

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ABSTRACT

This paper will highlight the use of high liquid volume plunger lift in the Southern Delaware Basin. This method of lift was first considered by COG Operating, LLC in an effort to bridge the gap for taking a well from flowing to rod pump. Historically in the Southern Delaware Basin this was accomplished with electric submersible pumps. One of the criteria for success was that plunger lift would be able to replace the electric submersible pumps and economically maintain the well on its natural decline. As of February 20th, 2015 COG has 10 wells in the SDB that have been successfully operating with high liquid volume plunger lift. Representative decline curves will be presented, along with operating histories on the successful wells in the project. The paper will be presented both from the prospective of the operator and then operating criteria from the vendor that have made this project a success.

BACKGROUND

As COG Operating LLC's horizontal wells in the Southern Delaware Basin (SDB) decline after initial production artificial lift is needed to continue to produce these wells. Because of the high flow rates associated with these wells the initial form of artificial lift historically had been an electrical submersible pump (ESP). Because of the high costs associated with ESP's in the SDB our team began to think outside of the box to figure out more economic ways of artificially lifting these wells before their production volumes declined enough to be placed on beam pump. Initially we tried to move large fluid volumes (more than 300 bfpd) with a beam pump, but our failure frequency was extraordinarily high and thus was not a very economic option. More recently we have shifted strategies and began installing a high liquid volume plunger lift system on these wells as an intermediate step between flowing and beam pump, hoping to effectively remove the ESP from the artificial lift equation. The purpose of this paper is to determine the viability of plunger lift as a replacement lift to ESPs in the SDB. Can it 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 an ESP? Secondly how do the lease operating expenses (LOE) of plunger lift compare to ESPs?

As Table 1 illustrates for the purpose of this paper we define high volume liquid plunger lift to have liquid volumes above 200 barrels of fluid per day (bfpd) and up to 700 bfpd. We have had instances of moving higher volumes than this, but in general we have not needed the assistance of artificial lift in this project area until liquid volumes fall below 700 bfpd. With true vertical depths (TVDs) around 10,000' on these wells they fall far outside of the "rule of thumb" range for plunger lift success, namely 0.4 MCF per barrel per 1000' of lift. We have also attempted to run this type of plunger lift system in other project areas without as favorable reservoir properties and fluid ratio's and did not have the success that we are having in the project area described in this paper.

DECLINE CURVE ANALYSIS

Figures 1-7 show representative decline curves for wells in the SDB placed on plunger lift. As shown in Figure 1 a thick vertical line serves as the indicator when plunger lift was installed in the well. The solid lines running through the oil, water, and gas production data are the forecasted declines put on the wells before artificial lift was installed. The purpose of these figures is to determine if the shape of the decline curve changed after plunger lift was installed.. Figure 1 seems to indicate that when plunger lift was installed there was no significant decrease in production. Figure 2 seems to show that we have a slight production decrease relative to the forecasted decline curve after this well was placed on plunger lift. This could be for several reasons: The plunger lift system could be curtailing our production, well test inaccuracies, or numerous other variables. Figure 3 seems to indicate that at times once the plunger had been installed, production has been above the forecasted decline of the well, and at other times production has been below the forecasted decline. Figures 4 and 7 seem to show that production may be slightly impacted by the installation of plunger lift as the forecasted decline curve is above the production volumes. Figure 7 also happens to have the lowest GLR of any well in the successful project area.

Plunger lift wells require stringent oversight and some of the variability in production could be attributed to altering plunger lift operating criteria such as shut-in time, fall time, pressure constraints, all affect the plungers' performance. Flow regimes and reservoir characteristics are incredibly complex especially in unconventional rocks that have nanodarcy permeability, induced hydraulic fractures, and potentially several different flow regimes. With that being said we are going to make a stab at why increasing drawdown in a high reservoir pressure environment might not have the benefit it would in a low reservoir pressure environment. Figure 4, from Vogel "Inflow Performance Relationships for Solution-Gas Drive Reservoirs", shows that for a solution-gas drive reservoir that at 60 percent of drawdown 80 percent of production is achieved and that at 80 percent of drawdown 93 percent of production is achieved. Thus in a high reservoir pressure environment the benefit of installing an ESP to quickly increase drawdown will not have a significant impact on production. We are not simply in a solution-gas drive reservoir, there are many other variables in this equation, but we have seen on wells that have installed ESP's in this area that there is not a significant production increase after the installation of an ESP. Thus if we cannot achieve a production uplift by incrementally increasing drawdown with an ESP the plunger system in this area is even more advantageous, because not only does it have a much lower operating cost (~$23,000 per month less than an ESP) it does not seem to sacrifice production.

ESP PROS/CONS

The major benefit of an ESP is the ability to quickly drawdown a well and thus increase production. While in the project area we see this "flush production" benefit for the first few days after we turn on the pump, this benefit quickly goes away and the well returns to its natural decline while it was flowing. As pointed out by Vogel, incremental production is difficult to achieve with incremental drawdown in a high reservoir pressure environment (The reservoir pressure on a typical SDB well is over 7,000 psi). Unfortunately the average lifespan of an ESP in the SDB is ~150 days. This is due primarily to poor power quality, fluid composition, 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.

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. Almost 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. Maybe the most important benefit of the high liquid volume plungers run in the SDB are the fact that they are bypass plungers that allow for faster fall times to reach the plunger stop. Using this type of plunger allows a shut-in portion of the operational cycle that is shorter than a conventional plunger cycle allowing more production from the wellbore. A disadvantage to plunger lift is the amount of time it takes to tweak and adjust operating parameters to match reservoir inflow. Thus it requires significant oversight and field personnel with knowledge and experience working around plungers to increase the chance of success.

ELECTRICAL SUBMERSIBLE PUMP VERSUS PLUNGER LIFT COST COMPARISON

The average monthly ESP related operating costs per well in the SDB for COG Operating is ~$25,000 per month. The charges that make up these costs are electrical consumption, monthly rentals, monitoring fees, workover rig time, pump repairs, etc. Thus far in the SDB the average plunger lift related operating cost per well is ~$2,150 per month. Thus the incremental operating cost savings per well of plunger lift relative to ESP in the SDB is ~$22,850 per month.

PLUNGER LIFT OPERATIONS

The plunger lift systems in the SDB are designed to operate on time or pressure settings depending on individual well behavior. Various types of plungers were run 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

COG has found that high liquid volume plunger lift can be installed and applied successfully on wells that meet certain GOR, WOR, and reservoir pressure criteria in the SDB. . As a very general “rule of thumb” we have thought that if we need several loads of 10.0 ppg brine water to kill a well to install artificial lift that it has the potential to be a successful plunger lift candidate. The installations of plunger lift have allowed COG to successfully bridge the gap between flowing and rod pump without any significant change to the decline curve shape and thus minimizing production curtailment. COG will continue to monitor this closely to ensure that production is not being sacrificed. The installations at the same time have provided significant cost savings when compared to ESPs. COG sees great benefit in working closely with our plunger lift vendor to monitor cycle times, operating pressures and plunger selection. COG plans to continue to install high liquid volume plunger lift on wells with significant GLRs and bottom hole pressures (BHPs). Finally we wish to thank COG management for allowing us the freedom to think outside of the box and try something “new” for artificial lift and the permission to present this paper.

REFERENCES

Fergusen, Paul, and E. Beauregard. "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.

Table 1
Successful Plunger lift Wells Initial 7 Day Production Average

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	Oil	Water	Liquid	Gas	GOR	WOR	GLR
	BOPD	BWPD	BFPD	MCFPD	MCF/BO	BW/BO	MCF/BBL
Well # 1	185	143	328	375	2.0	0.8	1.1
Well # 2	321	364	685	602	1.9	1.1	0.9
Well # 3	98	417	515	650	6.6	4.3	1.3
Well # 4	251	238	489	630	2.5	0.9	1.3
Well # 5	149	149	298	341	2.3	1.0	1.1
Well # 6	181	309	490	466	2.6	1.7	1.0
Well # 7	140	254	394	229	1.6	1.8	0.6
Well # 8	233	157	390	483	2.1	0.7	1.2
Well # 9	204	237	441	287	1.4	1.2	0.7
Well # 10	200	177	377	410	2.1	0.9	1.1

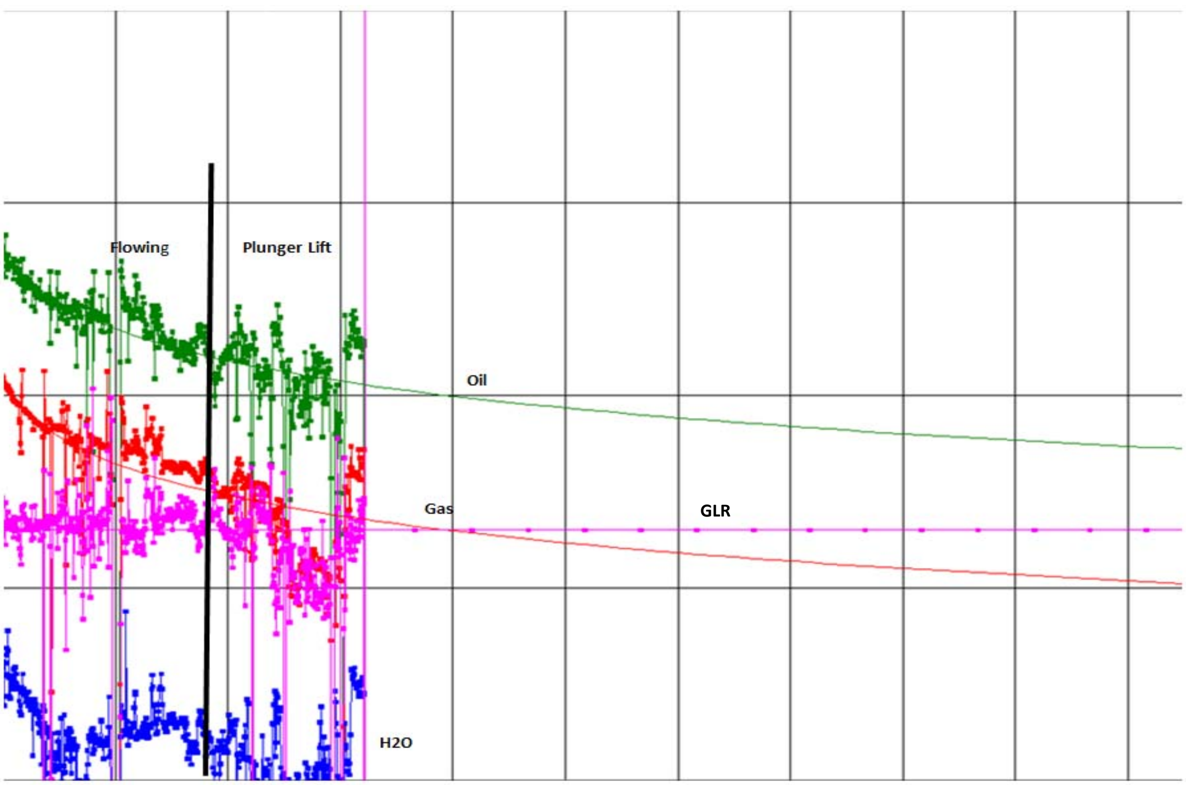

Figure 1 - Decline curve for plunger lift well #1

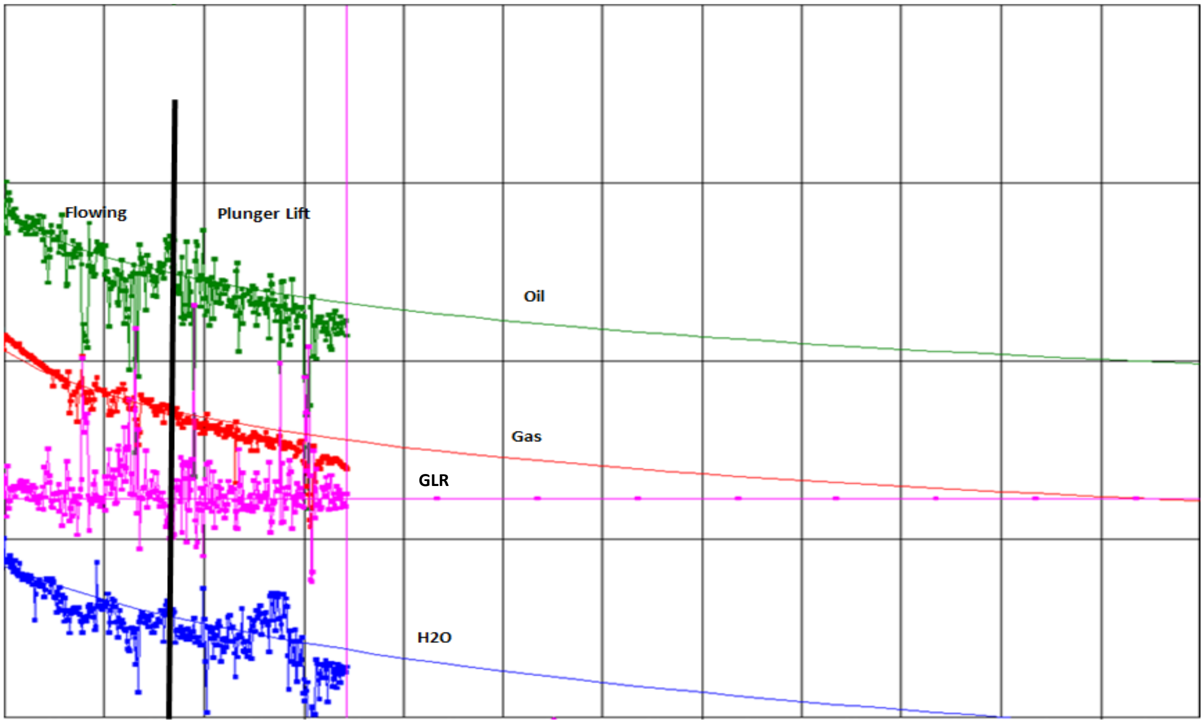

Figure 2- Decline Curve for plunger lift well #2

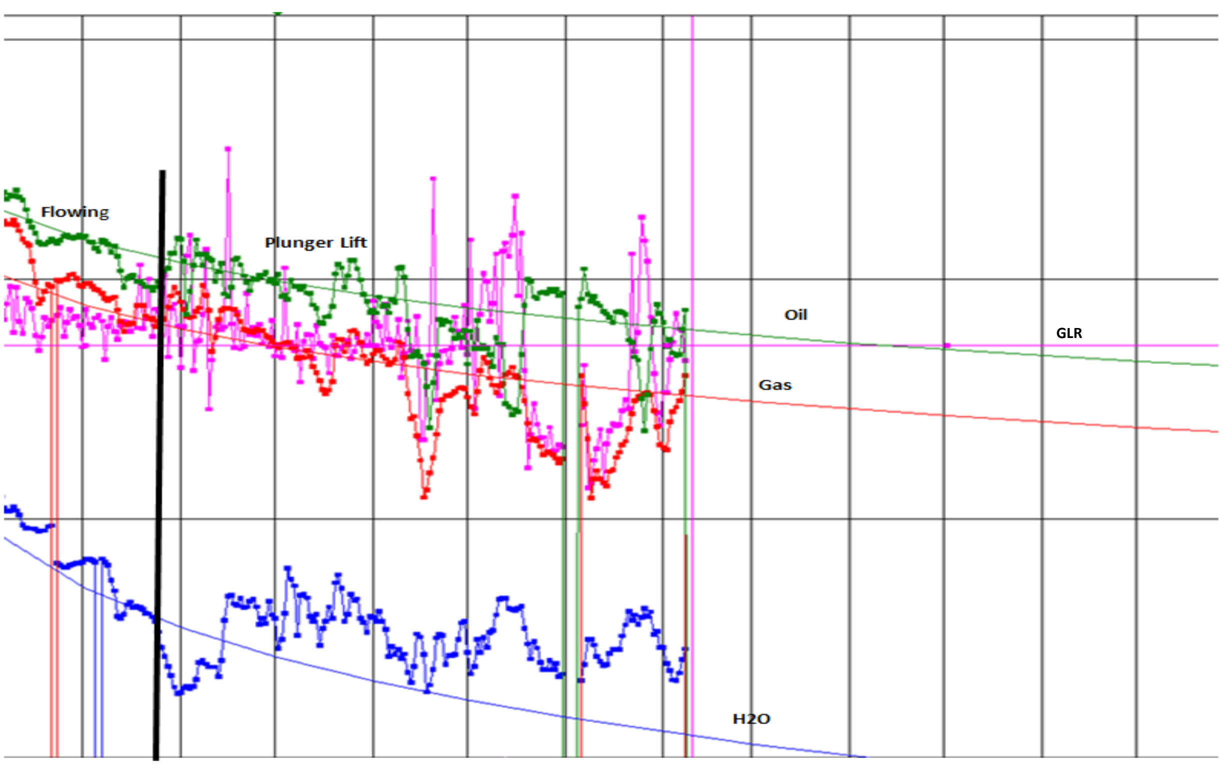

Figure 3 - Decline curve for plunger lift well #3

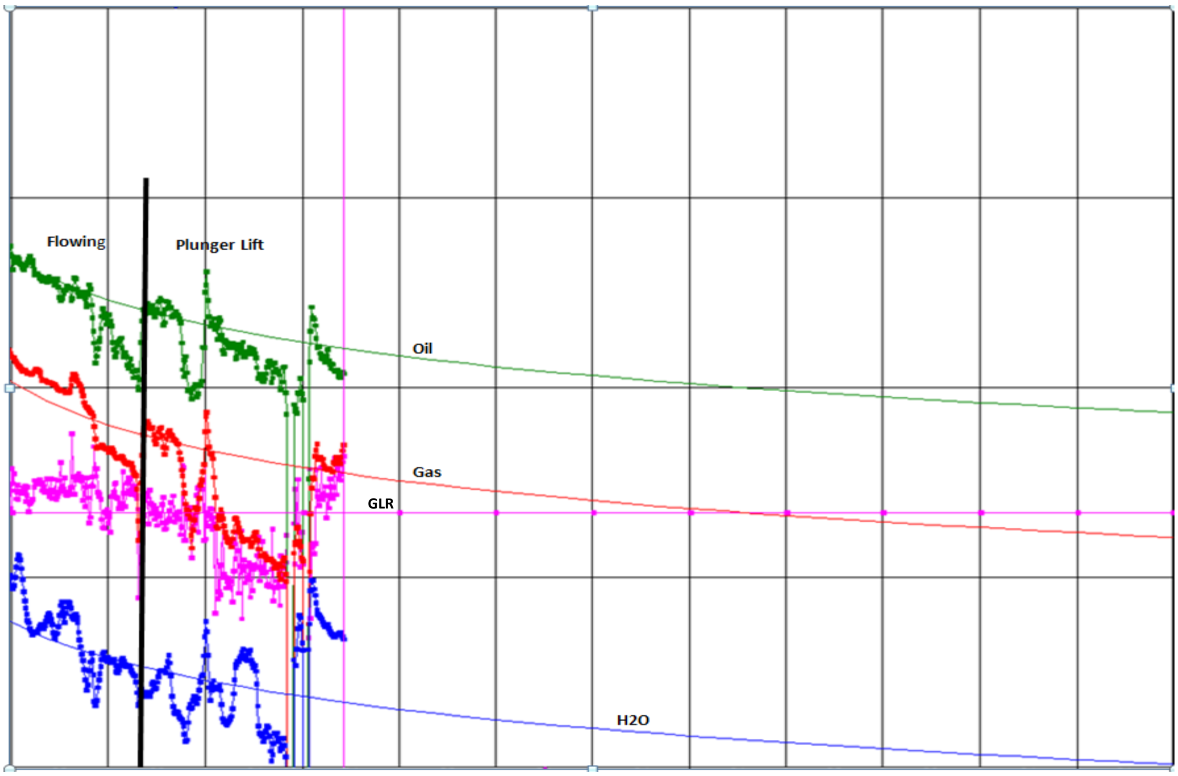

Figure 4 - Decline curve for plunger lift well #4

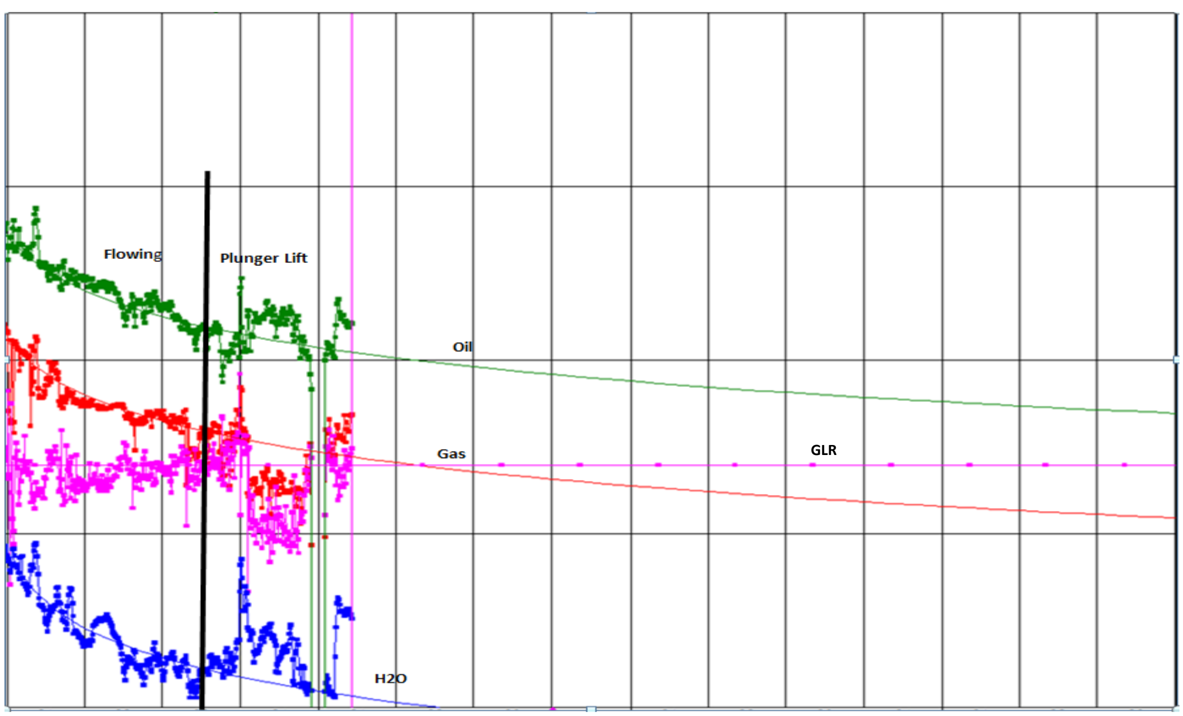

Figure 5 - Decline curve for plunger lift well #5

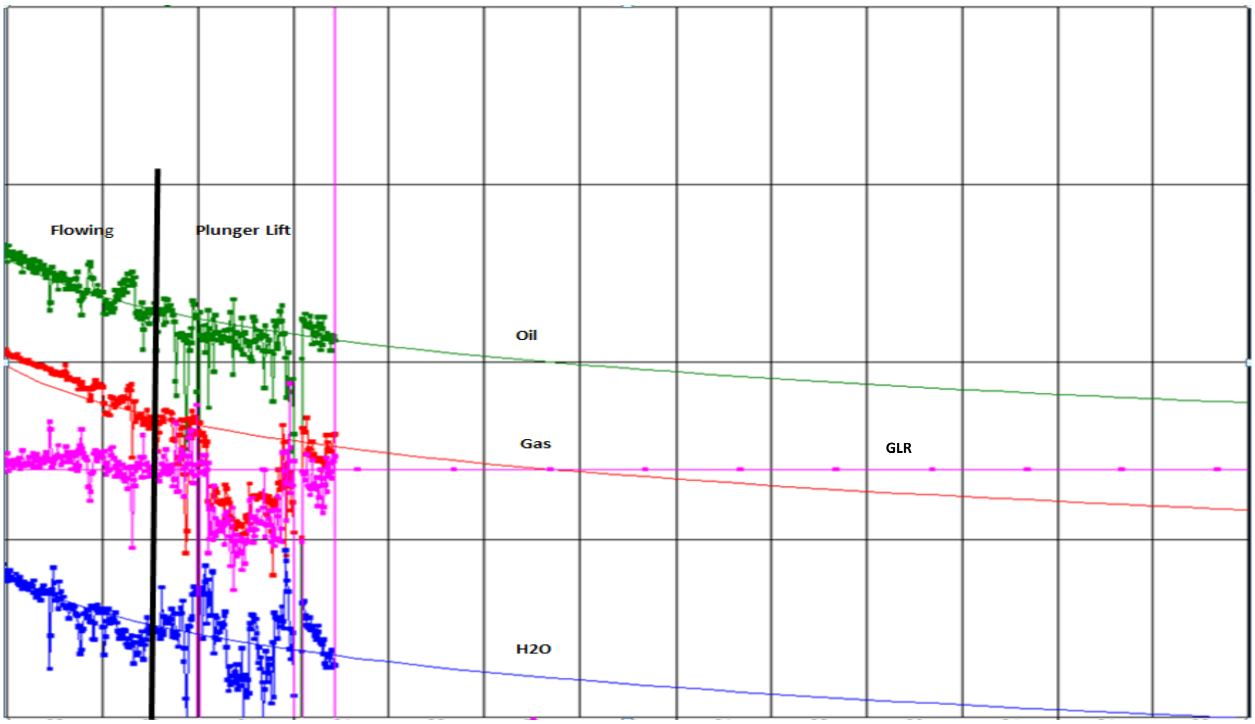

Figure 6 - Decline curve for plunger lift well #6

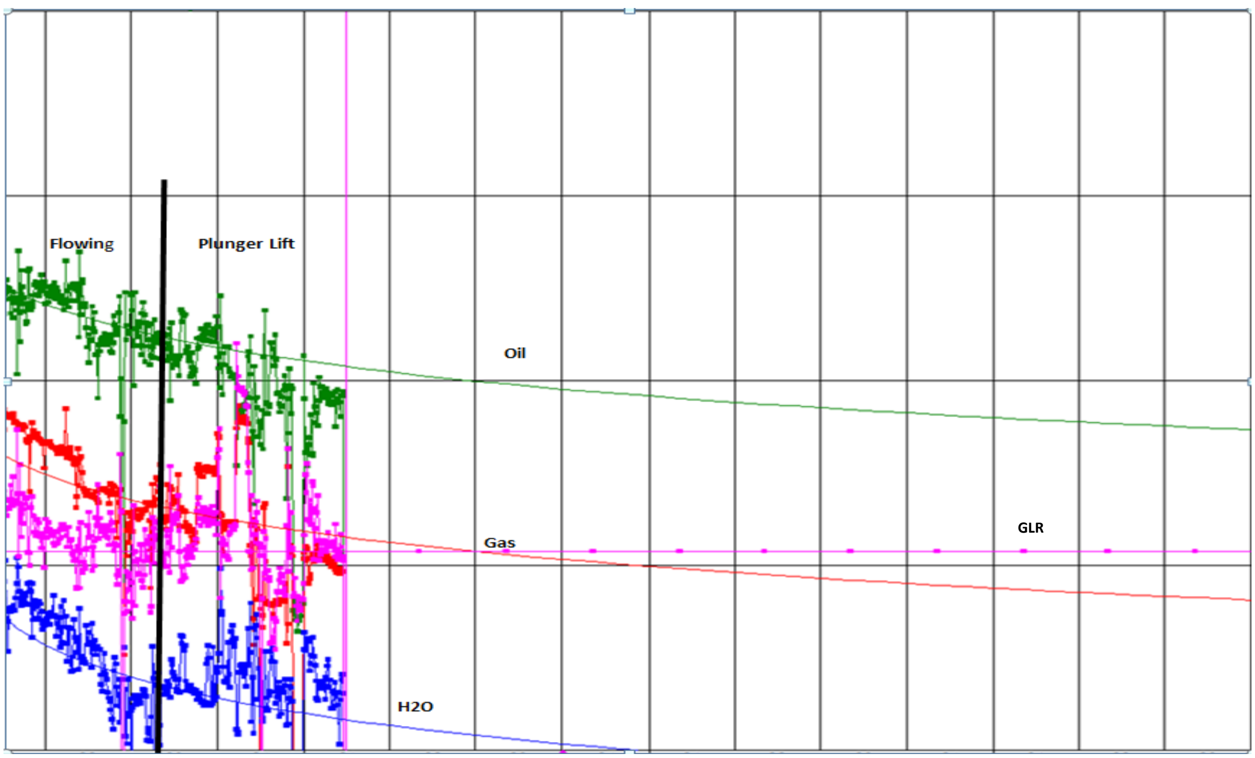

Figure 7 - Decline curve for plunger lift well #7

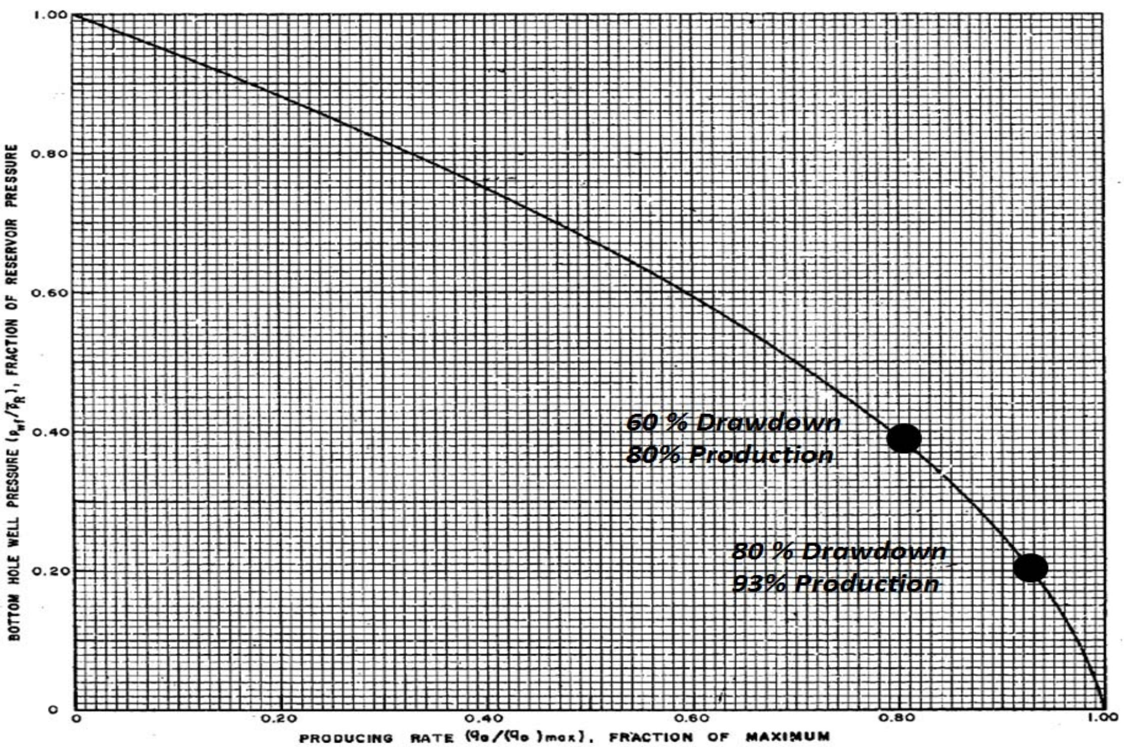

Figure 8 - Inflow Performance Relationship for Solution-Gas Drive Reservoirs