ARTIFICIAL LIFT SELECTION FOR HORIZONTAL UNCONVENTIONAL WELLS

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ABSTRACT

Horizontal Unconventional declines have a rapidly declining hyperbolic decline section and a slower declining exponential decline section. Rapidly changing production volumes from the decline curve and more rapid changes from slugging gas as a result of undulations in the horizontal leg plus sand from massive frac jobs result in challenges in artificial lift selection. This paper will explore these challenges.

INTRODUCTION

TWO PHASES OF DECLINE OF UNCONVENTIONAL WELLS

PRODUCTION DURING HYPERBOLIC DECLINE SECTION

Flowing design and artificial lift selection for unconventional wells is difficult since the initial phase of production declines very steeply (sometimes referred to as the Hyperbolic Decline). The well will have an initial high flow rate and then after a relatively short time in the life of the well, the production may drop to lower values of production and decline at a slower rate (sometimes referred to as the Exponential Decline). They are referred to as Hyperbolic and Exponential as these types of equations can be fit to the actual design in order to analyze and extrapolate actual results. (**Figure 1**)

Early Production: Since production will be high initially, the operator will realize a large percent of the profit to be obtained from the well during the first few years. Therefore, maximizing the production during the initial production phase can lead to increased values of the Net Present Value Profit. The initial production can be obtained by flowing the well followed by transition to a high-volume artificial lift method.

Equations below from: Numerical simulation of real field Marcellus shale reservoir development and stimulation *Hoss Belyadi, ... Fatemeh Belyadi, in Hydraulic Fracturing in Unconventional Reservoirs (Second Edition), 2019*

"In Hyperbolic decline the decline rate "*D*" is a function of production rate and can be defined as follows:

$$D = K\, q^b$$

where *b* is a constant and *K* is defined as follows:

$$K = \frac{D_\mathrm{i}}{q_\mathrm{i}^b}$$

Here D_i and q_i are initial rates and decline rates. The application of hyperbolic decline in unconventional reservoirs tends to overestimate the cumulative production."

From WSJ *By Christopher M. Matthews, Bradley Olson and Allison Prang* Updated Dec. 23, 2019 7:12 pm ET:

"Specifically, banks have begun questioning shale producers' predictions about their wells' initial rate of decline, which are proving overly optimistic, according to engineers. If shale wells, which produce rapidly early and then taper off, are declining faster than predicted, questions arise regarding how much they will ultimately produce. "

These wells are drilled in a hurry and may have doglegs, casing is usually small (hinders some methods of AL), do not have sand control and requite stages of lift. Many times the wells do not produce as would be predicted by reservoir principles which may be combination of lack of understanding of reservoir and how they are produced and also associated production problems

FLOWING

To illustrate some the concepts to be discussed, a set of well data is used to allow illustration of the performance of the flowing and artificial lifted production. Example well data follows:

Example data:

wht: 100 F, whp: 500 psi initially and trends to 100 psi after 12 years
bht: 175 F, GG: .7, GOR: 1500, API: 38, WG: 1.01
Pr: 7500 psi (initial)
WC: .6
Tbg ID: 2.441 (initial), Depth: 9500ft
Calculated:
Initial C: .00885619, n: .75 for the back pressure equation for inflow as follows:
$Q = C(Pr^2 - Pwf^2)^n$

The initial rate was recorded as 4400 bfpd so using the above equation the production Pressure at the EOT is calculated to be ~4000 psi.
This is shown for the tubing size initially in place, but also other flow paths are also shown in the following plot of initial IPR and flow path performances. We will assume the well has 5 ½ casing.
In order to make the following calculations and to show annular and tubing performance on one plot the following definitions are used:

Below are two definitions of effective diameter for annular flow:
The "Wetted Perimeter" method:

The "Wetted Perimeter" method:

$$Area = (\pi/4)*(ID_{outer}^2 - OD_{inner}^2)$$
$$WettedPerimeter = \pi(ID_{outer} + OD_{inner})$$

$$EffectiveDiameter = 4(Area)/WettedPerimeter$$

This looks reasonable until you do the algebra and see that Effective Diameter really equals (ID_{outer} - OD_{inner}) at that point it seems less pertinent.

The "Petroleum Engineering" method (see Petroleum Engineering Handbook, edited by Howard B. Bradely, Third Printing, 1987, published by The Society of Petroleum Engineers, equation 49, page 34-27) uses:

$$EffectiveDiameter=((ID_{outer}+OD_{Inner})^2 * (ID_{outer}-OD_{Inner})^3)^{(1/5)}$$

The Petroleum method will give you effective diameters that are about 40% higher than the Wetted Perimeter method. To use either one, calculate your effective diameter and then just use it in any of the fluid-flow equations that call for ID. So, the PEH method is used in the following plot to illustrate flow different possible flowing flow paths.

Flowing Well Calculations:
The following flow paths are examined in the below plot. Annular effective diameters are from the SPE formula above:

First a “typical” decline curve for this example is shown to see the range of flows vs time. See **Figure 2:** As can be seen the rate drops from ~4000 bpd to ~1000 bpd in about 1.3 years for this example. Other fields might show more or less early decline. This was for 2 7/8’s being in place.

The following flow paths are modeled for this well:

Tublar/s	Deff
5 1/2	5.012
5 1/2 x 2 3/8	3.982
5 1/2 x 2 7/8	3.603
5 1/2 x 3 1/2	3.018
3 1/2	2.992
2 7/8	2.441
2 3/8	1.995

For the above the 5 ½ by gives the highest rates but it seems unstable near the initial IPR plotted above See **Figure 3**. Vogel is used above but there are more advanced transient models that one could use. An example is “Inflow Performance Relationship for Unconventional Reservoirs (Transient IPR) by Shahamat et al, SPE-185975-MS **Figure 4**. They show IPR’s in the Hyperbolic decline, that the Pr remains the same (as fractures drained?) followed by the Exponential decline where the low perm matrix is involved in the production. See the following figure.

ANNULAR GAS LIFT

The 5 ½ by itself cannot be gas lifted. Annular gas lift can be accomplished with tubing and casing. For example, choose 5 ½ x 2 7/8’s annular flow and examine gas lift as follows: The first plot below shows the annular gas lift with gas injected into the casing at the bottom of the tubing. For this initial condition, the rate goes from 4900 (flowing) to about 5200 bpd with gas lift. As the IPR declines percent increases with gas lift would still occur. **See Figure 5**.

For comparison, only the 2 7/8’s is used with gas lift. See **Figure 6**. The max rate for the current conditions is less. If larger casing in place, the annular gas lift would show much more production initially.

The above results give an idea of what gas lift can do. Remember gas lift has low power efficiency and will not lower the pressure on the formation as well as a pump that is operating with no problems so be sure a move to gas lift is warranted. Regardless of the method of production (high flow or high rate AL), make sure that when you go to high rates you are not stimulating more sand production.

Next the use of ESP's will be examined.

ESP's

ESPs can produce high rates and as such may be candidates for unconventional wells when rates are high, and the decline is steep. Most unconventional wells produce some gas, so the ESP's require that gas separation is used to achieve the potential of the centrifugal pump stages. When gas is not separated then the performance of the stages is reduced, and PIP is higher than desired. As attempts are made to lower pressure on the well, the lower pressure increases the gas volume at intake and there is a point that gas degrades the stage performance significantly. Therefore, one can use gas separation relationships to determine the minimum intake pressure before the gas entering the pump significantly degrades the stage performance. If a separator is used, then these predications can be made with the separator efficiency as a parameter. Low separator efficiency means more of the free gas at the intake is allowed into the pump see below

Dunbar's Correlation uses the flow rate of the oil, water and gas into the pump at the pump intake pressure and temperature to determine the minimum pump intake pressure before the pump stage performance will be degraded. When PHI is less than one, pump head degradation is not predicted. When PHI is greater than one, head degradation is predicted.

$$\Phi = \frac{935}{Pip}\left(\frac{bgpd}{bopd + bwpd}\right)^{\frac{1}{1.724}} = \frac{935}{Pip}\left(\frac{GVF}{1 - GVF}\right)^{\frac{1}{1.724}}$$

GVF is the gas void fraction (times 100 = the free gas percentage)
Setting PHI = 1, the Pip vs GVF (or % free gas) can be plotted.

$$Pip = 935\left(\frac{GVF}{1 - GVF}\right)^{\frac{1}{1.724}}$$

Figure 7 shows how using the Dunbar correlation, the lowest pressure and highest rate possible before the ESP stages show problems with gas can be predicted.

As seen in **Figure 8** ESP's can produce more than annular gas lift for this case. Finally, at low rates the difference is much less.

As seen in **Figure 9**, ESP's can produce quite a bit more than gas lift up only the 2 7/8's initially.

To achieve deeper intake a dip tube design is often used in horizontal wells, but it also can and is used with ESP's.

Figure 10 shows a shrouded dip tube with vent holes. This reference contains discussion of several variations of dip tubes below ESP installations. Further discussion of dip tubes used with beam pumps is in the following section on Exponential decline although some high rate beam pump installations can also produce a lower portion of the Hyperbolic decline. If rates are such that above critical occurs past the shroud then problems can occur.

For higher rates before decline takes the rate down, quite a bit of equipment is required for an ESP installation. The following are approximate example designs as the well declines with the PIP input as 1000 psi just to give an idea of equipment required:

BPD	#Stages	~BEP	Hp,req'd
5700	475	6000	480
5000	426	6000	430
4000	410	4300	370
3000	422	3000	280
2000	336	2200	190
1000	337	1150	80

ESP's may NOT be good choice if:

1. Solids are produced and not controlled
2. Gas present after separation entering the pump does not allow low intake pressures
3. Power supply is erratic
4. Conditions are such that there are a lot of starts/stops

JET PUMPS

Jet pumps can deliver both high rates and low rates. If the right equipment is selected (free pumps) then pumps can be changed by pumping and without pulling tubing or use of wireline. They for instance could be alternative to ESP's as the rate declines.

A general rule of thumb is that a jet can draw an oil well down to *approximately* 10% of the vertical hydrostatic. For the 9500 ft. deep example used here the possible intake pressure is about 1000 psi. For 100% water the drawdown possible is less. They can handle some gas and some solids. For 100% water the rule is drawdown cannot be lower than 25% of hydrostatic as water creates more severe cavitation situation.

To give an idea of what's needed for Jet installations from 9500 ft. with the above data the below designs are developed from the Coleman jet pump program. Since many applications stay away from power fluid pressures greater than 4-5000 psi, most of the below designs are out of the normal. The designs could better with larger casing but in general the larger rate designs would have to be further optimized or would not be too practical. For the data shown only the lower rate portion of the hyperbolic decline would be practical with jet pumps.

Pump Size	Power Press psig	Power Fluid Rate bblpd	Horse Power	Non-Cav Rate bblpd	Prod. Rate bblpd	Pumping Bot-hole psig	Nozzle Area inches	Throat Area inches
J:18	7536	13744	1957	6081	5700	1000	.1257	.4513
I:17	6549	9644	1193	5407	5000	1000	.0855	.375
H:16	6027	7494	853	4605	4000	1000	.0661	.3127
G:14	5722	5189	561	3199	3000	1000	.0452	.2165
F:12	5361	3584	363	2125	2000	1000	.0314	.1452
D:9	4863	1981	182	1171	1000	1000	.0177	.0804

Other techniques such as shallow set Moniteau pumps could be investigated but the choices of ESP and /or Gas Lift are the AL methods used most by industry currently. Downtime, failures with solids, gas interference etc. are reasons that Gas Lift is gaining some popularity.

HYPERBOLIC DECLINE PRODUCTION CONCLUSION

One can model the best flow path and implement the best flow path (which is constantly changing) but to get the maximum NPV high volume or high volume seems to be desirable. However a word of caution here as some operators seem to get more cumulative by working with chokes and not necessarily flowing the well at the maximum possible. With no solids, and the ability to separate gas, then high volume pumps could be the choice. However, with solids and frequent pump failures gas lift could be the choice requiring least manpower and adjustment from operators with time.

PRODUCTION DURING EXPONENTIAL DECLINE SECTION

Although the **Figure 11** is for a specific example it helps one to understand that most of the value for non-conventional wells is added in the hyperbolic portion of the decline curve. Once one gets into the exponential portion of the decline curve much less additional value is added, and economics of additional investments become marginal. Each incremental investment must be carefully evaluated, and risk minimized. Since rates are low, to be profitable the method of production or artificial lift must be efficient, have long run lives, and demand little manpower. Many marginal fields have existed in the US for many years so the best practices for operating wells that produce small amounts have been developed. What is somewhat new is that the unconventional wells are horizontal leg. For best life, the pumps are set in a relatively vertical portion of the wells. So deep drawdown presents a problem for pumps. The intake for gas lift can be taken to the lateral and later for even lower rates, plunger can be run as deep as perhaps 60 degrees.

Beam Lift:

Gas Lift has already been introduced and gas lift can be used over most if not all the production of the well. It is especially needed if the well produces solids or excessive gas making gas separation difficult for pumping systems. However, if solids are not present and if gas production is not so high that separation cannot be achieved, then pumps can be considered.

Beam pump systems are the most used artificial lift system in the US and the world. They can achieve low intake pressures if gas separation is possible and if solids do not cause failures and other problems.

In many areas it is said that you should show why beam systems cannot be used before discarding their use.

The Weatherford Chart included in the Plunger section below shows that beam pumping can move larger volumes of fluid than may be practical. **Table 1** shows a more practical perspective of beam lift targets. Polished Rod Velocity is a very good indicator of failure frequency. Industry accepted guidelines are shown below. Following these guidelines can lead to the most cost-effective type of lift. In the example problem when lifting from 9500' it is reasonable to consider transitioning to beam lift in the 200 BFPD to 300 BFPD range. Commercially available design software is available to refine these general targets.

Polish Rod Velocity = SPM * SL

- Conventional Units
  - Stroke length > 100" Max Speed = 1500/Unit Stroke
  - Stroke length < 100" Max Speed = 1300/Unit Stroke
- Mark Units
  - Stroke length > 100" Max Speed = 1200/Unit Stroke
  - Stroke length < 100" Max Speed = 1000/Unit Stroke

Lessons Learned for Cost Effective Beam Lift:

Industry expert, Lynn Rowlan, says that the Artificial Lift Energy Optimization Forum (ALEOC) benchmarking study conducted by Texas Tech had at least two significant findings. First, all sophisticated operators have access to design equipment that allows them to properly design beam lift equipment without overloading. Second, operators differentiate themselves by their operating procedures. In this section, we will focus operating procedures.

The Oxy TXDS Team experience supports Lynn's conclusion. The TXDS Team transitioned from a Design Review Process with a failure frequency (FF) greater than a 0.9 failures/well/year to an Operational Review Process that resulted in decreasing the FF to 0.4 failures/well/year in November 2018. The Design Reviews analyzed failed wells using design programs and best practices to configure downhole equipment. The Operational Reviews analyzed Pump Off Controller Set Points and minimized the number and intensity of incomplete fillage cycles. Also considered in Operational Reviews are spacing requirements, gas locking, and avoiding incomplete fillage/overtravel/tag.

<u>Packer Type Separators with Dip Tubes</u>

There is inherent difficulty to producing deep horizontal wells. The two most significant issues are 1) the large slugs of gas that accumulate are released in the undulations of the horizontal lateral, and 2) the significant volumes of sand the is produced as a result of the massive frac job. When the well has reached steady state conditions the gas slugs appear in regular intervals and may exceed the capacity of the downhole separation equipment resulting in gas interference in the downhole pump and slug flow up the casing. The configuration of wells with horizontal legs make it impossible to use the preferred gas separation method of the Natural gas Separator. In addition, the sand produced can shorten the lift of downhole equipment.

Separators for Sucker Rod Pumps (SRP) cannot exceed certain liquid rate or they drag gas bubbles into the separator. Limits for poor boy separators are listed below by Echometer. See **Table 2**. **Figure 12** exemplifies the difference in downhole equipment configurations between a with natural separator and poor boy separator.

In order to manage these problems packer type separators with dip tubes are often installed. The desired effect of a dip tube installation is to operate in stable flow in the dip tube section. The lower hydrostatic head that results from the better use of the well's gas to help lift the liquids increases the pressure draw down and fluid volumes. **Figure 13** shows a packer separator set at the kickoff point on the left and packer separator with dip tube extended to near lateral on right.

Slug flow and gas interference are reduced but not eliminated and sand flowback is managed. This new technology is evolving may not achieve the desired results. Care should be taken to evaluate the 1) the probability of success and 2) the increased risked cost of an expensive workover (or lost well as a result of solids build up on top of the packer.) Significant improvements are continuously being made and historical success rates may not be representative of current technology. It may be possible to remove up to ~200-400 psi flowing pressure using these devices.

<u>Incomplete Fillage/Overtravel/Tag:</u>

An issue associated with rod pumping deep wells is called incomplete fillage/overtravel/tag. Several factors have led to this being an issue.

The changes in acceptable loading standards for metal sucker rods (resulting in stretchy rod strings) when applied to pumping deep (from 7,000' to 12,000') increases the severity of fillage/overtravel/tag. In the last twenty years, the API Goodman Diagram used in sucker rod design has been recognized as being very conservative. Today, much of Industry is using 1) a Service Factor of as high as 1.3 or 2) use the high strength equation for all metal rods (including grades C, D, K, and KD). Loading up rods strings has resulted in lighter rod strings, smaller pumping units/motors, and decreased capital expenditure operating expenditures.

Another impact of loading rods up is stretchy rod stings increase the difficulty in spacing out the bottom hole pumps. Spacing out wells to maximize compression ratios (CR) can be challenging. The CR changes as the well pumps off. Lynn Rowlan describes this in the SWPSC Paper *<u>OVER-TRAVEL CAN OCCUR ON BOTH THEUPSTROKE AND DOWN STROKE.</u>* **Figure 14** illustrates a pump cycle in which incomplete fillage results a significant overtravel of 5.5" and a tagging bottom with a force of 5439 lbs.

This incomplete fillage/overtravel/tag cycle is common in non-conventional wells and is a major contributor to failures. Spacing out is one way to avoid this type failure. However, it can require spacing out very high maybe 30" to 40". This in turn results in a very low compression ratio and poor gas handling characteristics. The pumps gas lock easily. Once this occurs, it is a common practice for field operations to respace the well in a tighter more conventional manner to get the well pumping. As the well reaches pump off, we will once again have incomplete fillage which will result in an equipment damaging tag. As a result, field operations will raise the well up to avoid tagging. An endless cycle of respacing often occurs, and failure rates are high.

<u>Pump Off Controllers (POC) and Incomplete fillage.</u>

Cavitation decreases the equipment life of positive displacement pumping systems. Incomplete fillage in downhole sucker rod pumps can be considered a form of cavitation. The traditional pump off controller senses cavitation and shuts down. Thus, the cavitation of a POCs detrimental to equipment life. However, if a pumping unit does not adjust produced volumes to inflow (as in running all the time), cavitation will occur on more strokes and equipment will be damage more than when a POC is not used. Historically industry has accepted the POCs reduce failures. It is generally accepted that on/off POCs target a daily run to 18-20 hours with about 20 cycles per day. Each cycle has a least one cavitation stroke. It is likely the pump will have 1-10 cavitation strokes per cycle. The intensity of each incomplete fillage stroke is measured by the stored and released energy at the point of incomplete fillage.

- KE= $(3.14\ D^2 * H * SpGr * 62.4) * (v^2 * 1/(g*g/gc)$ ft-lbf)
    - KE is energy or intensity, ft-lbf

- SpGr is fluid specific gravity,
- D is pump diameter, ft
- H is net lift, ft
- *v* is the velocity at the point of incomplete fillage, ft^2/s^2
- s seconds, s
- g 32.3 ft/s^2
- g/gc lbm/lbf

It is generally accepted that the incomplete fillage should be me limited to the very top of the downstroke where the Velocity (*v*) is low and the smallest diameter (D) of pump used to achieve the desired production. When the net lift (H) is large from pumping at 8,000' to 12,000' the energy in each cavitating stoke is significant and must be minimized. It is recommended that pump off cycles be kept to a minimum. There is a tradeoff between lost production from maximum draw down and damaging equipment. An economic evaluation should be run to determine the optimum pump off cycles. In the 2018 SWPSC paper Gentle Pump-Offs Can reduce Operating Expenses, Jeff Jenneman describes the Idle Time Calculator which make this economic evaluation.

Effective Methods of Managing the Incomplete fillage/overtravel/tag cycle.

- Using time clocks to avoid incomplete fillage can be an effective way to manage this.
- Using Jack Shafts to match inflow to pump displacement is an effective way to manage this.
- Utilizing Variable Speed Drives on pumping Units is another way of matching inflow to pump displacement which minimizes incomplete fillage issues. Instead of stopping and starting, when fillage is high in the pump the controller speeds the pumping speed up. When fillage is just becoming incomplete the controller slows the pumping speed down allowing the pump to fill again. Between the higher and lower speeds there is a dead band where changes are not made. This eliminates rod loads caused by starting and stopping. The industry uses this type of controller if SRP's are used where slugging is high. When rates become lower, the on/off controller seems to work as well.
- Utilizing Variable Slippage Pumps (VSP) is another way to manage this. When properly operated VSP do not have incomplete fillage cycles. Matt Nichols with Noble Energy wrote this paper on *Avoiding Gas Interference While Rod Pumping High GOR Wells.* In the paper he describes the effectiveness of using in Non-conventional application. Offsetting the benefits of the benefits of this pump are the difficulties in properly spacing them out. The pumps space out to the top not the bottom. As a result, field operations often have trouble operating at the preferred spacing. I general it can be difficult to properly operate these pumps.

Sinker Bars

Running Sinker Bars is recognized best practice and is recommended on all sucker rod designs to minimize compression on the lower portion of the rod string and to add stiffness to the string immediately above the pump. The objective of these improvements is to minimize or eliminate helical buckling.

Predictive sucker rod design programs such as SROD calculate helical buckling effects. A positive buckling tendency or a negative number at the bottom of a given taper indicates the potential for buckling and associated failures.

All sucker rod strings without sinker/weight bars, regardless of design or material, will experience buckling in the bottom sucker rod taper. Because large diameter sucker rod sections are stiffer than small diameter sections, use large diameter sucker rod sections above the pump to minimize helical buckling.

Note: *The current methods of sizing sinker bars are to eliminate compression (with a safety factor) in the rods above the SB's. However, compression in a diagnostic card is a function of the input drag coefficients. The shape of the diagnostic card gives some information. The current default is 200 lbs. of pump resistance which gives rod compression for most rods and the 200 lbs. will buckle rods of most any size. Since the* *current method requires you to know the drag coefficients, the default on programs is in excess of rod buckling, and even with SB's in place, the SB will buckle for most cases. It might be as well to determine a length and weight of SB's that seems to work across your field to minimize rod failures. If one or a few wells show significant compression above the pump such as double lipped rod parts, then more SB's could be tried.*

It is recommended to use the lengths of Sinker Bars in the tables below as compared to the length of sinker bars calculated in commercially available design programs. But if there are signs of significant compression at the bottom of the rods (bent barrel, solids, too tight of pump fit, etc) it would be better to solve these problems instead of putting in more and more sinker bars.

<u>PLUNGER LIFT</u>

When rates become lower, the well can possible be lifted by plunger lift. The chart below shows plunger rates approximately possible with higher rates possible from more shallow wells. It is reported that in some cases plunger can lift several hundred bpd, but many plunger lift wells produce on a few bpd. Many plunger lift wells require no outside source of energy. The plunger helps to lift a slug of liquid with minimal fallback. This translates to improved lift of liquids from a gas well. A plunger lift well is illustrated below. The computer closes the well to allow the plunger to drop to the bottom and well pressure to build. The well opens to allow the well's own pressure and flow to lift the plunger and the liquid to the surface.

Plunger lift:

- Plunger can lift wells flowing below critical (liquid loaded))
- Can lift deep wells
- Cannot lift too much liquid .. Many wells < 5 bpd
- Need about 400 scf/bbl-1000' for conventional plunger
- Need buildup pressure when well shut in (Pcas>1.5*Line Pressure)..maybe within an hour
- Well must be shut in long enough for plunger to reach bottom
- Well must flow long enough for liquids to accumulate for the next cycle
- Spread sheet available to analyze/optimize plunger
- Desirable rise velocity is:
- 500 fpm < Vrise < 1000 fpm
- Can fall in horizontal well to about 30 degrees inclination… possibly as high as 60 degrees
- Padded plunger may not work so well above about 40 degrees inclination
- Plunger travel (rise and fall) can now be measured by relatively new industry technology
- Too much solids production may prevent plunger use

Example: If a well is producing 200 mscfD and making 20 bbls/MMscf/D
The well is 4000 ft. deep.
It is making 200000/20 or 10,000 scf/bbl
It needs to be making 400 scff/bbl-1000' or 400 x 4 = 1600 scf/bbl
The gas//liquid ratio is more than the requirement so by the gas rule it is feasible.

In Figure 15 Weatherford illustrates approximate volumes that can be produced form a given depth with a plunger.

Note the higher rates possible are from the shallower wells. The plunger lift method can
Lift from deep depths if the well has the gas to liquid requirement and sufficient pressure buildup when shut in.

As an unconventional well declines to lower rates plunger can often work. However, if there is not enough gas to liquid or pressure buildup then gas assisted plunger may be required. For instance, if a plunger well is performing poorly because it has a low gas to liquid ratio, then gas can be injected (down the annulus) until performance improves. For instance if a well is trying to produce with only 300 scf/(bbl-1000'), then gas can be injected (GAPL) until the well produces above 400 scf/(bbl-1000') which should make plunger lift possible. Also, the well may be losing energy and cannot build enough pressure on each cycle to lift a nominal liquid slug. Gas can be injected into the well on the off cycle until well pressure in the well is sufficient to lift the liquid slug. Although GAPL may require a compressor, it may be considerably more economical to use compared to resorting to an expensive SRP system.

Progression of type of plunger to use shown on a critical rate chart (below critical the well begins to liquid load) at and below the critical rate. Note that GAPL is at the bottom. Progressive plunger might also be listed at the bottom of the chart as the well declines to rates well below critical. Some advice received from L Rowlan, Echometer, on the sequence of plungers to use as the well declines below critical show in **Figure 16**.

CONCLUSIONS:

Reserve estimates for horizontal non-convention wells are generally viewed as overly optimistic. One contributing factor maybe the lift type selection. It is important to choose the appropriate lift type to maximize the value of the wells. Slugging gas and sand production are significant factors in lift type selection.

Most of the value of the non-convention horizontal well is realized in the Hyperbolic Portion of the decline curve. In this section, industry currently seems to prefer Gas Lift with ESPs being a close second. One reason is that Gas Lift can be applied for the economic life of the well. Also gas lift is not troubles by excessive solids or gas production. However, gas lift efficiencies are poor late in the well's life.

The Exponential Portion of the decline curve demonstrates marginal economics. Investments and risk should be closely evaluated carefully. A significant influence of the economics of beam lift are the operating procedures. When rates are low with pumps plunger and/or GAPL can be considered. However, solids and excessive gas can defeat pumps or SRP systems and then gas lift can be considered even in the low rate exponential tail of the decline curve. Gas lift can be converted to plunger or GAPL at low rates or can be continued at low rates but more efficiently with smaller tubing.

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3. Brian Ellithorp & DJ Snyder, "Improved Results in Rod Pumps with Isolated Tailpipe Systems Through Advancements in Components and Analysis" Proceedings of the Annual Meeting of the SWPSC, 2018.
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Table 1 – Examples of Practical/Cost Effective Beam Lift Designs for Deep Wells

Depth	Rate	Gear Box Transition Points	Structure	stroke	taper	spm	PRV	pump dia
Conventional Units with Metal Rods								
7000	25	80	173	54	66	6.0	324	1.25
	50	114	173	64	66	7.9	506	1.25
	75	160	173	64	66	10.1	646	1.25
	100	228	173	86	66	10.7	921	1.25
	200	456	213	120	76	9.1	1090	1.5
	300	640	256	120	86	10.5	1262	1.75
	400	640	256	120	86	8.8	1056	2
	500	912	256	144	86	10.2	1469	1.75
9000	100	228	213	86	66	8.9	763	1.25
	200	456	305	120	76	9.0	1085	1.75
	300	912	305	144	86	9.2	1323	1.75
	400	912	365	168	86	9.0	1510	2
11000	100	320	256	100	66	8.05	805	1.25
	200	640	365	144	76	8.48	1221	1.5
	300	912	365	144	86	10.05	1447	1.5
Special Geometery Units with Metal Rods								
7000	25	80	173	54	66	6.0	324	1.25
	50	114	173	64	66	7.9	506	1.25
	75	160	173	64	66	10.1	646	1.25
	100	228	173	86	66	10.7	921	1.25
	200	456	213	120	76	9.1	1090	1.5
	300	640	256	120	86	10.5	1262	1.75
9000	100	228	213	86	66	8.9	763	1.25
	200	456	305	120	76	9.0	1085	1.75
	300	912	305	144	86	9.2	1323	1.75
11000	100	320	256	100	66	8.05	805	1.25
	200	640	365	144	76	8.48	1221	1.5
Conventional Units With Fiberglass Rods								
7000	25	40	143	48	1.0, 0.875	8.2	391	1.25
	50	80	173	48	1.0, 0.875	8.7	418	1.25
	75	114	173	54	1.0, 0.875	9.3	502	1.25
	100	160	173	64	1.0, 0.875	9.2	586	1.25
	200	228	200	86	1.0, 0.875	9.5	817	1.50
	300	456	256	100	1.25, 1.0	9.0	900	1.75
	400	640	305	120	1.25, 1.0	9.3	1116	2.00
	500	640	305	120	1.25, 1.0	9.0	1080	2.25
9000	100	228	200	86	1.0, 0.875	10.1	869	1.25
	200	320	213	100	1.0, 0.875	10.1	1010	1.25
	300	456	256	120	1.0, 0.875	10.7	1284	1.50
	400	640	305	120	1.25, 1.0	9.5	1140	1.75
	500	640	305	144	1.25, 1.0	9.4	1354	2.00
11000	100	228	256	100	1.0, 0.875	9.4	940	1.25
	200	456	305	120	1.25, 1.0	7.9	948	1.25
	300	640	365	120	1.25, 1.0	8.9	1068	1.5

Table 2 - Gas Separator Capacity, BPD with Separator Above Perforations

Outer Barrel Nominal Size	Barrel ID, in.	Dip Tube OD, in.	Dip Tube ID, in.	Annulus Area, sq. in.	Max. Received Flow Rate, BPD
3 1/2	2.992	1.660	1.25	4.87	243
2 7/8	2.441	1.660	1.25	2.52	126
2 7/8	2.441	1.315	1.00	3.32	166
2 3/8	1.995	1.660	1.25	0.96	48
2 3/8	1.995	1.315	1.00	1.77	88
2 3/8	1.995	1.050	0.75	2.26	113

Collar-size Gas Separator Gas and Liquid Capacity (Echometer)

Outer Barrel Nominal Size	Barrel ID, in.	Dip Tube OD, in.	Annular Area $in.^2$	Liquid Capacity BPD*
3.	2.75	1.315	4.6	229
3.75	3.5	1.315	8.3	413
4.5	4.26	1.5	12.5	624
5	4.75	1.66	15.6	778
5.6	5.35	1.66	20.3	1016
* Based on the 50 BPD/sq. in. annular space rule of thumb				

Table 3: Sinker Bars for 2 7/8" Tubing: Lengths of 1.625" Sinker Bars Tabulated

Pump Dia./ Depth	1 1/4"	1 1/2"	1 5/8"	1 3/4"	2"	2 1/4"
4000	100	125	150	150	150	175
6000	150	175	200	225	225	250
8000	200	250	275	275	300	350
10000	250	300	325	350	375	425

Sinker Bars for 2 3/8" Tubing: Lengths of 1.50" Sinker bars Tabulated

Pump Dia./ Depth	1 1/4"	1 1/2"	1 5/8"	1 3/4"	2"	2 1/4"
4000	125	150	150	175	200	200
6000	175	225	225	250	275	300
8000	250	275	300	325	375	400
10000	300	350	375	400	450	500

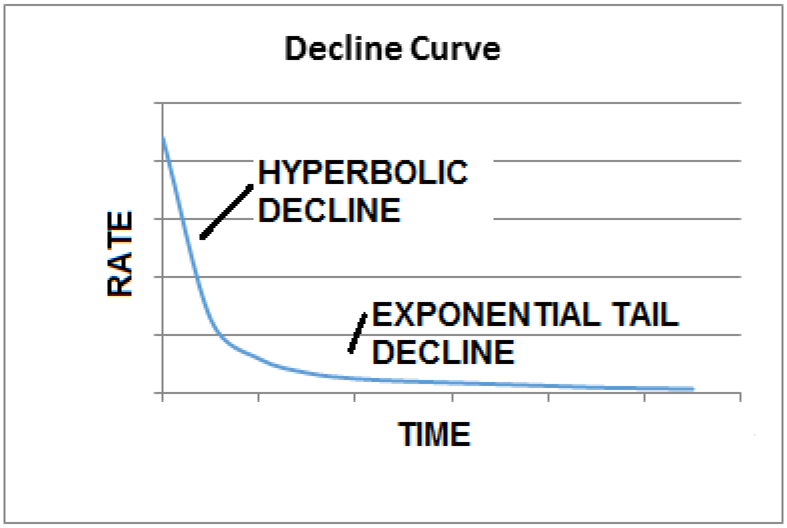

Figure 1 - Example of Hyperbolic and Exponential Decline Curve - From: Numerical simulation of real field Marcellus shale reservoir development and stimulation *Hoss Belyadi, ... Fatemeh Belyadi, in Hydraulic Fracturing in Unconventional Reservoirs (Second Edition), 2019*

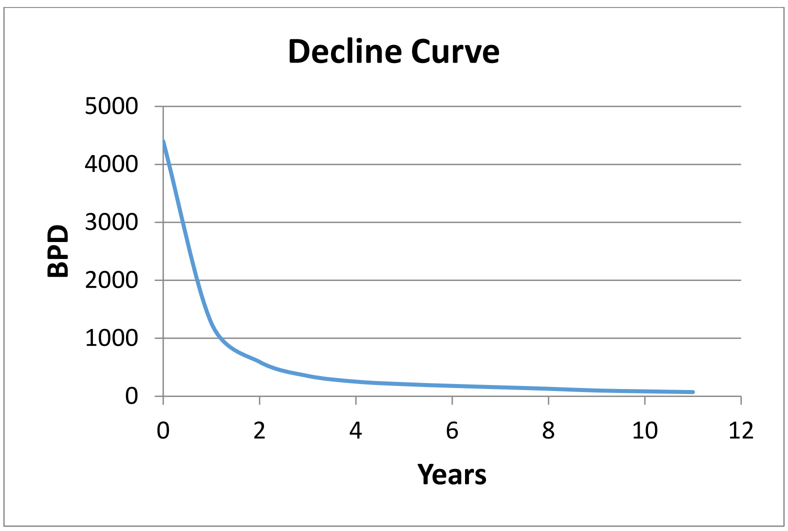

Figure 2 - Stereotypical Decline Curve

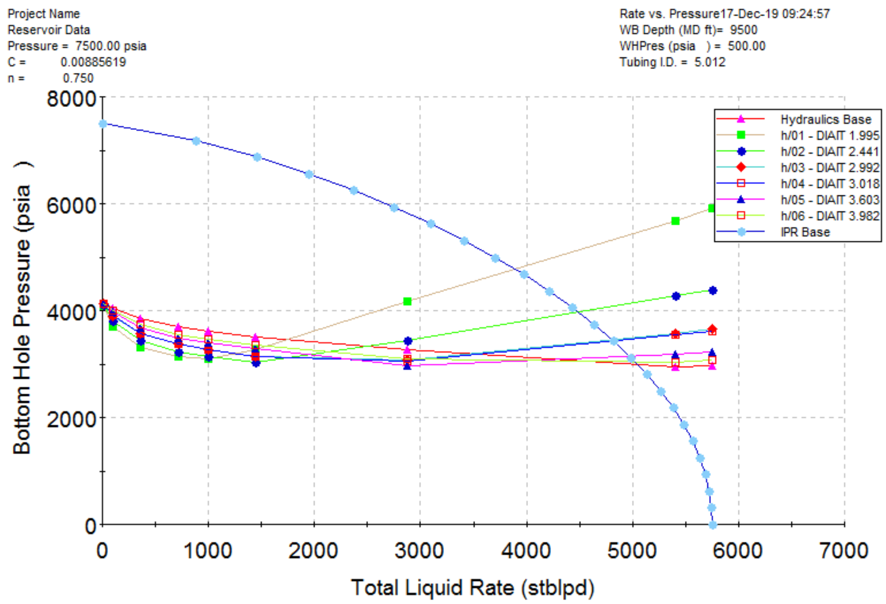

Figure 3 – Example of Sizing a Flowing Well with 5 ½" Casing and Various Sizes of Tubing

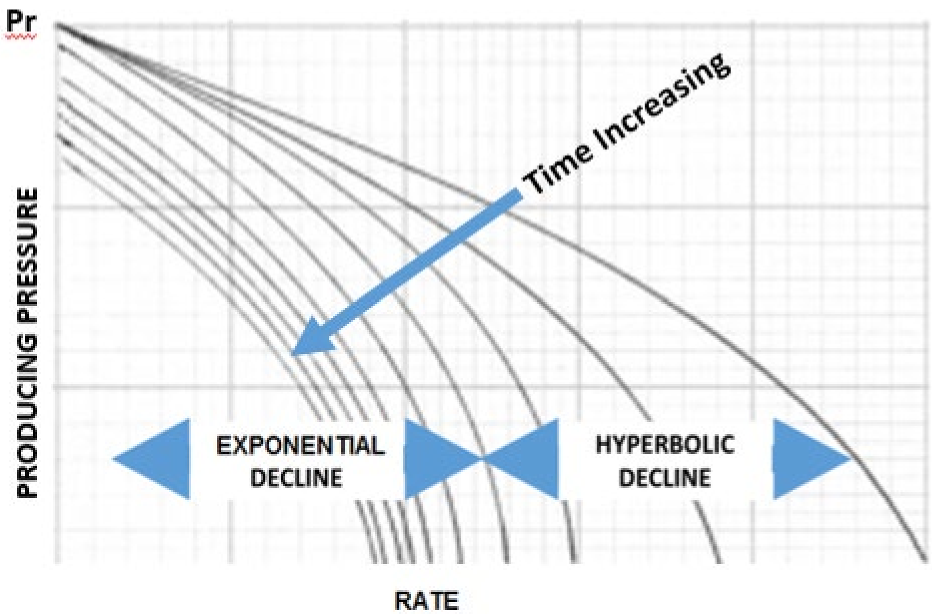

Figure 4 - An example is "Inflow Performance Relationship for Unconventional Reservoirs (Transient IPR) by Shahamat et al, SPE-185975-MS.

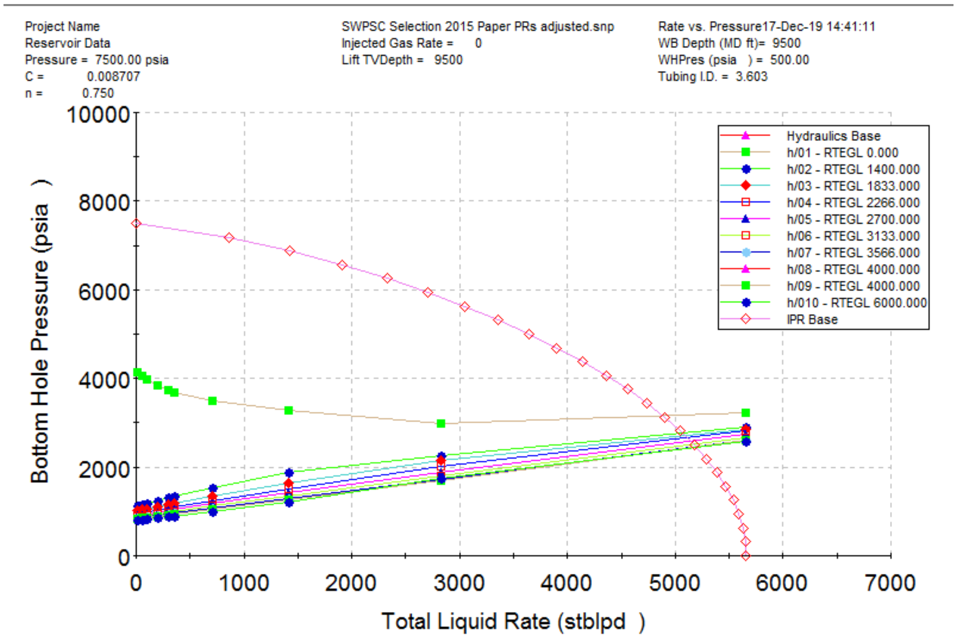

Figure 5 – Example of Gas Lift Design with 5 ½ Casing Annular Gas Lift and Gas Injected into The Casing at The Bottom Of The Tubing.

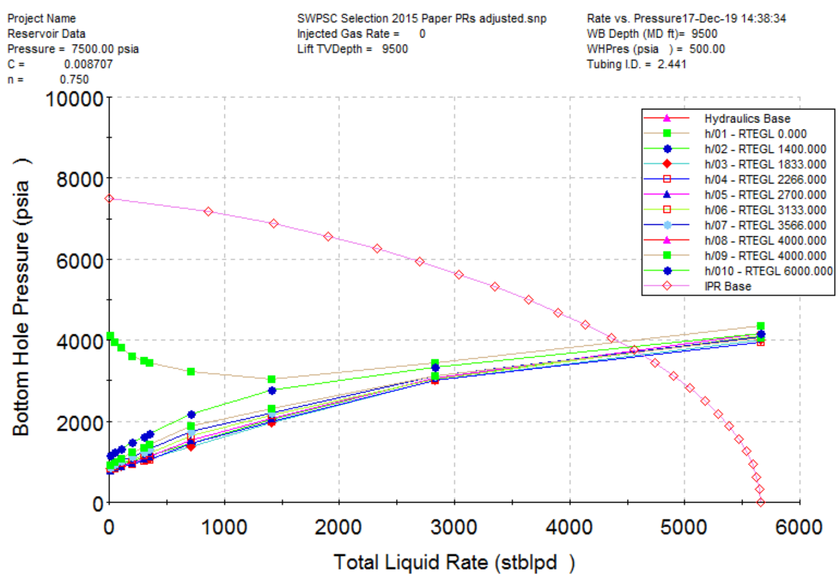

Figure 6 – Example of Gas Lift Design with flow up 2 7/8" Tubing

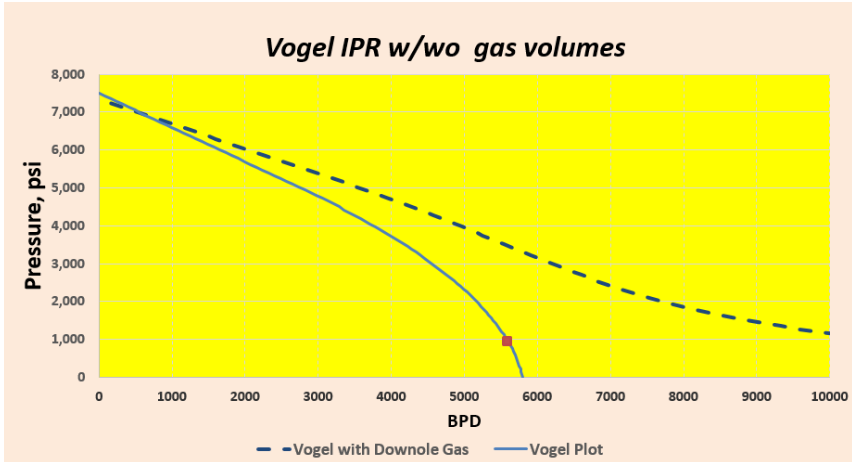

Figure 7 – Vogel IPR w/wo Gas Volumes. No lift performance plots included.

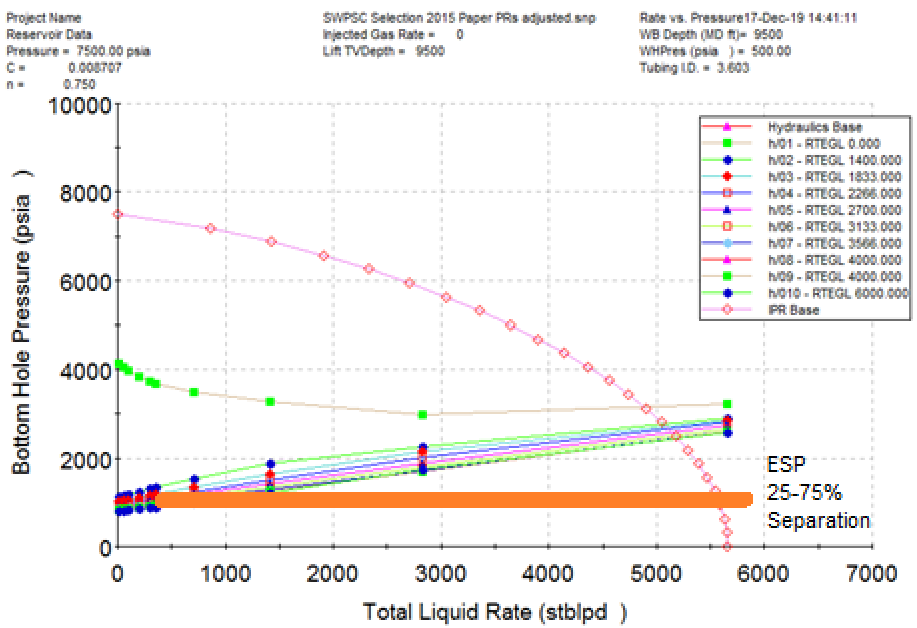

Figure 8 – 5 ½" Casing With ESP design and Annular Gas Lift and Gas Injected into The Casing At The Bottom Of The Tubing. ESP and Gas Lift performance curves plotted across the IPR

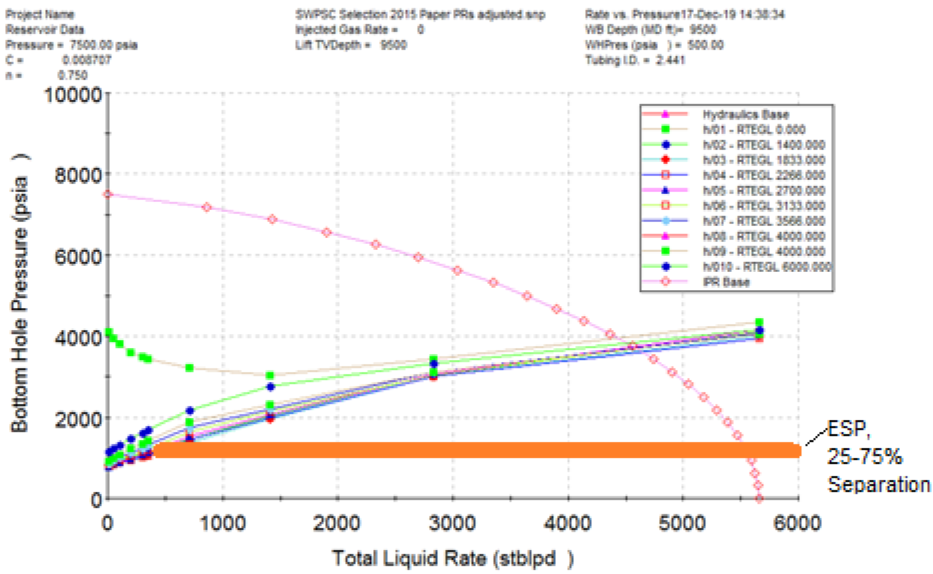

Figure 9– ESP Design With 5 ½” Casing with Gas Lift up only the 2 7/8” tubing initially.

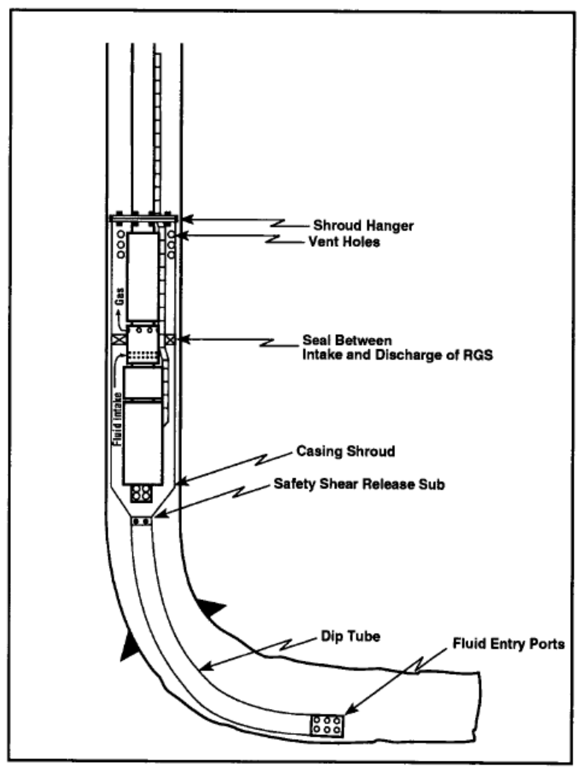

Figure 10 – Example of a shrouded dip tube with vent holes from SPE 24763, “Successful Submersible Lift Operations in Gassy Horizontal Wells, Pearsall Field, Texas” by T.G. Freet and K.P. McCaslin, Oryx Energy Co.

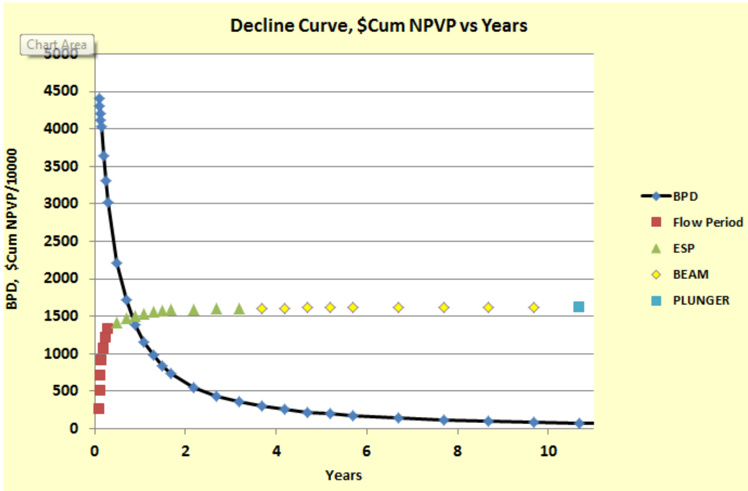

Figure 11 - Cumulative Net Present Value generated by methods of lift over the decline period from "Lea, J., Mike Brock, and Subash K. Kannan. "Artificial Lift with Declining Production." *Proceedings of the Sixty-Second Annual Meeting, April 22-23, 2015*. Southwestern Petroleum Short Course, Lubbock

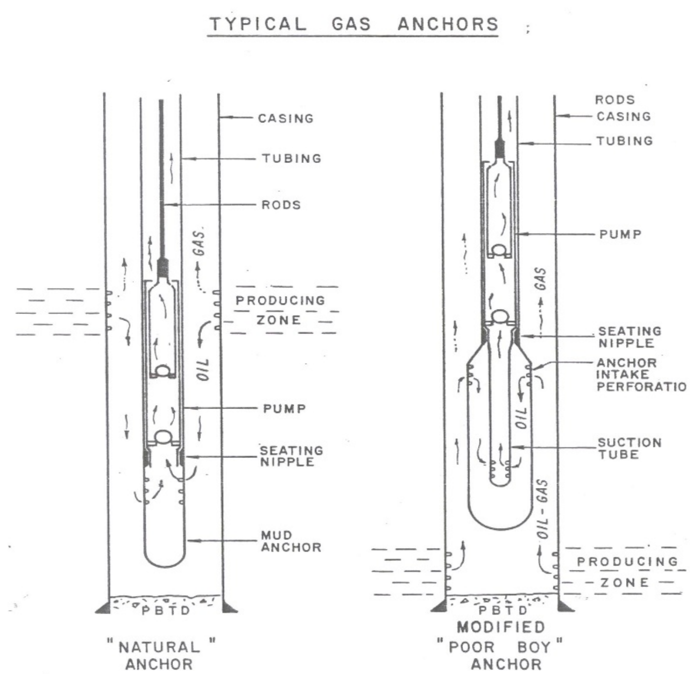

Figure 12 Is an Example of The Difference Between A with Natural Separator and Poor Boy Separator

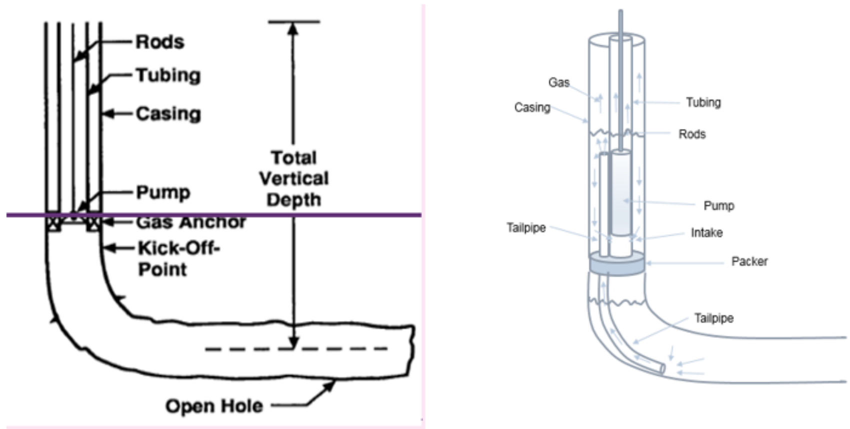

Figure 13 Is an Example of The Difference Between A Packer Separator and Packer Type Separator w/ Dip Tube.

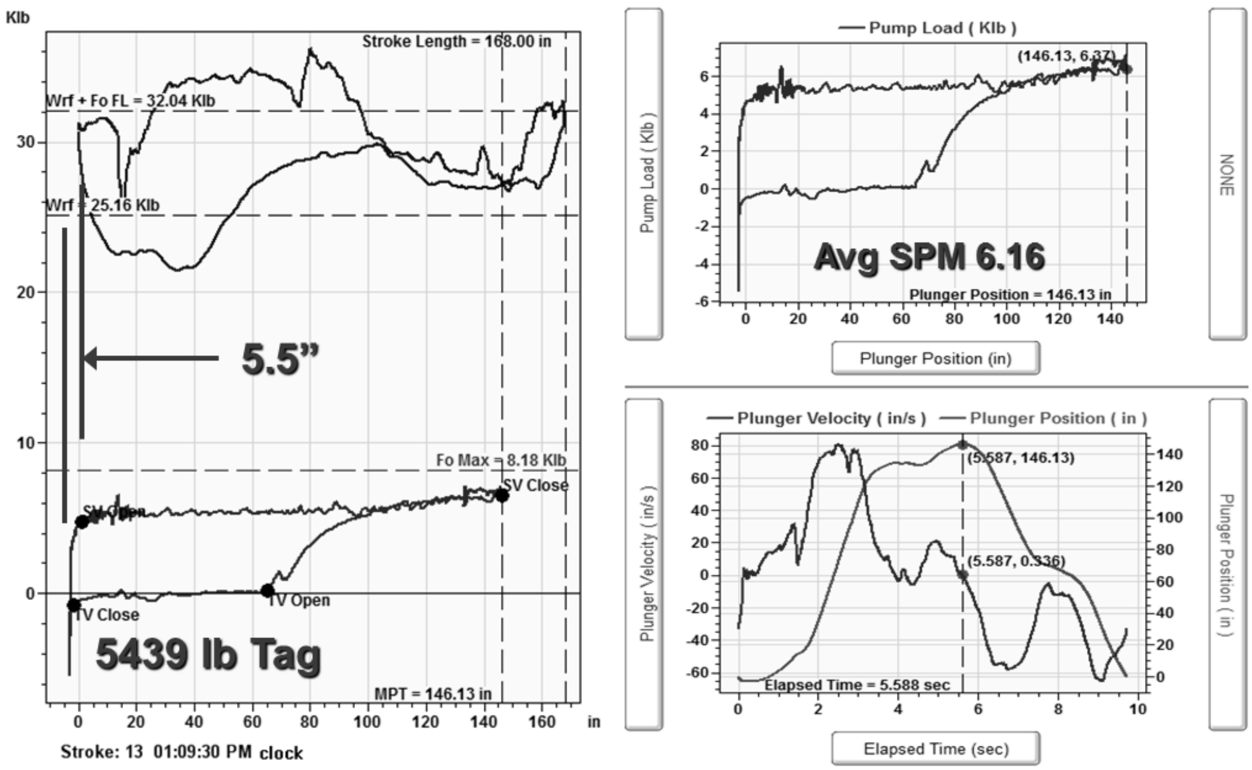

Figure 14 illustrates a pump cycle in which incomplete fillage results a significant overtravel of 5.5” and a tagging bottom with a force of 5439 lbs. From Over-Travel Can Occur on Both the Upstroke and Down Stroke.”, Proceedings of the Annual Meeting of the SWPSC, 2018

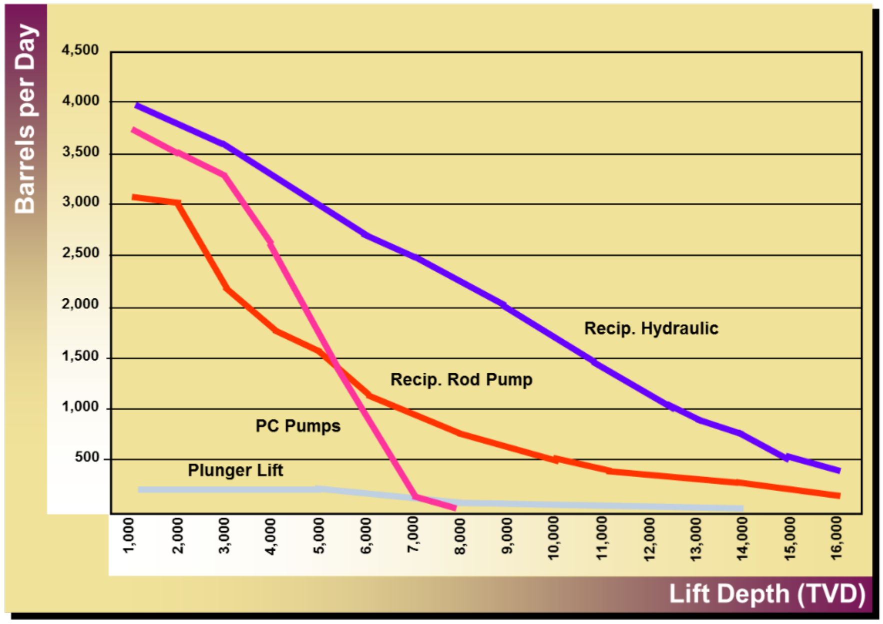

Figure 15 – Weatherford shows approximately production volumes per depth for plungers

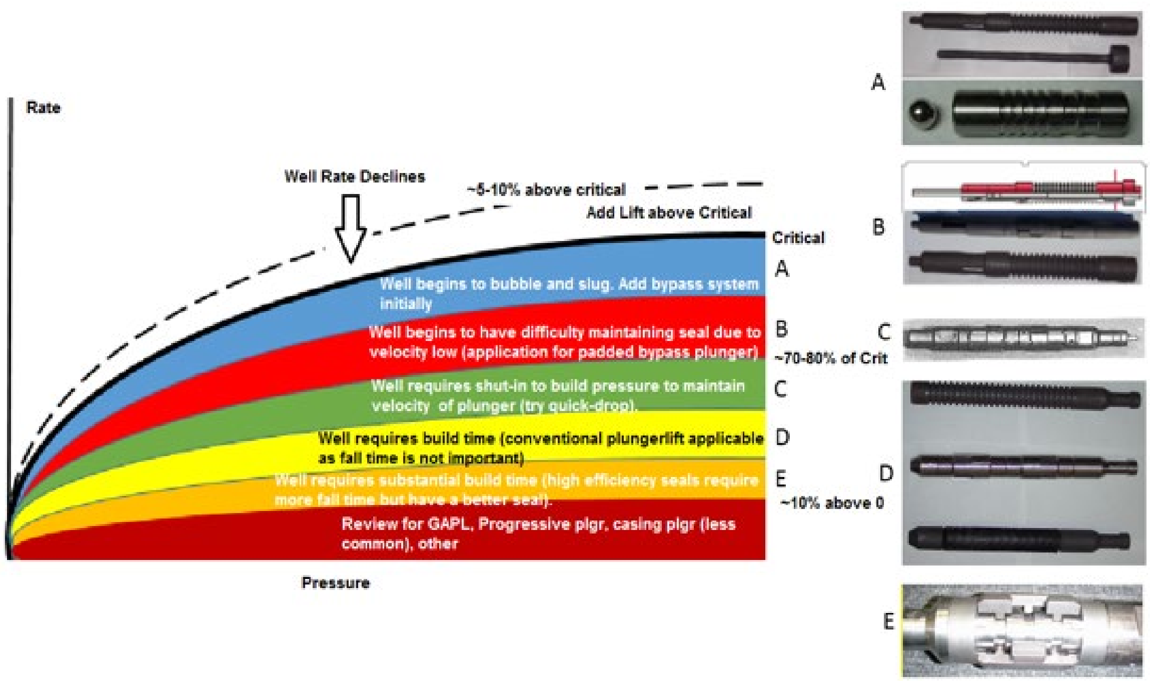

Figure 16 - L Rowlan, Echometer, on the sequence of plungers to use as the well declines below critical.