Collar Size Separator Performance and Animation

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Abstract

The collar size separator is used to separate liquid from free gas downhole in a well before the liquid is drawn into the pump. The pump and pumping system are much more efficient if gas free liquid is drawn into the pump chamber and the pump is full of liquid rather than having some free gas in the pump chamber.

If liquid is available to fill the pump, additional production will be obtained from the well if the pump chamber is filled completely with liquid. Also, the loading on the pumping system is much better and the pumping equipment will last longer before requiring servicing.

The separation process in a downhole gas separator is very complex. An animation shows the behavior of gas and liquids in a separator when typical concentrations of liquid and free gas are surrounding the gas separator and pump. The animation is to scale and duplicates the performance of an actual well. The flow of liquid and various sizes of free gas bubbles are shown to help the viewer understand the process of separating free gas from oil. The flow rates in the separator and dip tube are determined from calculated plunger velocity and production rates of an actual well.

Downhole Gas Separators

Often, the main cause of inefficient operations is an inefficient downhole gas separator. Inefficient gas separators can be identified by obtaining an acoustic liquid level test which indicates a high gaseous liquid column above the pump and the analysis of dynamometer data which indicates incomplete pump fillage. Periodic acoustic liquid level tests and dynamometer measurements should be performed to verify that the downhole gas separator is operating efficiently. Tapping bottom with the pump, running the pumping unit at excessive speed, operating the pumping unit for excessive periods of time, increasing the tubing pressure or increasing the casing pressure is not the proper procedure for correcting inefficient downhole gas separation.

Generally the operator has three options with regard to downhole gas separation design depending on the well conditions, producing gas rate and producing liquid rate:

1. Natural Down Hole Gas Separator
2. Packer Type Gas Separator
3. Collar Size Gas Separator

If the pump intake can be placed at least 10 feet below the bottom most perforations the <u>Natural Gas Separator</u> provides the highest liquid capacity for a given casing diameter. Figure 1 is a schematic diagram of the downhole natural gas separator and Table 1 gives the corresponding liquid capacities for various casing diameters and dip tube sizes.

When the pump intake cannot be located below the perforations (horizontal completion, presence of small diameter liner, etc.) the <u>Packer Type Gas Separator</u> isolates the casing annulus and allows using most of the area between the casing and the separator to direct the liquid downwards to the pump intake and achieve gas/liquid separation with an efficiency comparable to that of the Natural Separator.

The majority of wells that are completed with the pump intake above the perforations include a separator attached to the bottom of the tubing as shown in Figure 2 with the objective of diverting most of the produced gas up the annulus and admitting mostly liquid into the pump. The mechanism inside the separator relies on balancing buoyancy and drag forces that act on gas bubbles so that the gas is allowed to slip upwards while the downwards velocity of the liquid is trying to drag the gas bubbles towards the pump intake as shown in Figure 2.

Most often, the gas separators that are set above the formation are made from common oilfield materials such as tubing, perforated subs, collars, bull plugs, etc. without considering that the resulting separator design may not operate efficiently for the particular well conditions and desired liquid and gas rates. These separators, known as “Poor Boy” type separators, are generally built as illustrated in Figure 3.

The thick wall of conventional tubing or conventional perforated subs reduces the area available for separating gas from liquid which decreases the capacity of the gas separator. The outer diameter of the perforated sub is less than the diameter of the collar. This further reduces the area between the inside of the perforated sub and the internal dip tube and hence reduces the liquid capacity. Most conventional gas separators utilize perforated subs with small 1/4" or 3/8" holes or narrow slots for fluid entry from the casing annulus into the gas separator. When the pump is on the upstroke, liquid and gas are drawn into the pump and a differential pressure exists between the casing annulus and the interior of the gas separator causing fluids to flow into the gas separator since the inside of the gas separator has a lower pressure than the casing annulus when the pump is on the upstroke. On the down stroke, liquid flow into the pump ceases. The pressure on the inside of the gas separator rapidly approaches the pressure on the outside of the gas separator in the casing annulus. Fluid motion within the separator is governed only by gravity forces and gas bubbles will rise to the top of the separator by buoyancy but will have difficulty exiting through the small perforations from the separator into the annulus due to the absence of a pressure differential.

Many conventional, perforated tubing-subs, "Poor-Boy" gas separators operate at low efficiency. This fact has been verified by hundreds of tests such as that displayed in Figure 4 that shows a well with significant liquid above the pump intake but only 34% pump fillage which is less than the percentage of liquid present in the casing annulus indicated as 57% from the measurement of the casing pressure buildup (0.5 psi in 2 minutes) corresponding to 18 MCF/day of annular gas flow.

Relatively simple modifications of the Poor Boy separator that are based on the physics of gas/liquid flow in the well and the behavior of gas bubbles in liquids have resulted in the design of a much more efficient separator, the Collar Size Separator described in the following section.

Collar Size Downhole Gas Separator

As the name indicates one of the features of this separator design is that the outer diameter of the separator is the same as the outer diameter of the tubing collar to which the separator is attached. Several advantages exist for the gas separator outer barrel being the same diameter as the tubing collar as depicted in Figure 5:

- Some operators are hesitant to run a gas separator into a well that the diameter of the gas separator exceeds the diameter of the tubing collar because of potential retrieval problems. Having the gas separator O.D. the same as the tubing collar O.D. will help to prevent sand fill around the bottom collar which might hinder removal of conventional perforated sub or oversized gas separators.
- Another reason for a collar-size gas separator is that at least some of the ports in the gas separator outer barrel should be near the casing wall because studies[1,2,3] have shown that where tubing touches the casing wall is an area of higher liquid concentration as shown in Figure 6. Since the OD of the separator is the same as the OD of the collar the whole separator will naturally rest on the low side of the hole.
- The third reason for an outer barrel being the same diameter as the tubing collar is that a larger internal diameter can be used to maximize the area of the between the inner wall of the separator and the dip tube.

Thus, a thin-wall gas separator with the O.D. of the outer barrel being the same diameter as the collar constructed in accordance with the guidelines shown schematically in Figure 7 , should probably be used in a majority of wells where the pump is above the formation. The performance and the pump fillage for the well that was outfitted with the "Poor Boy" gas separator (Figure 4) improved dramatically when a properly designed collar size separator was installed as shown in Figure 8. (Additional examples of field performance of wells using Collar Size Gas separators will be presented at the SWPSC and an addendum will be distributed to the participants.)

Physical Description of Flow inside Collar Sized Separator

Multi phase flow inside the separator involves upwards flow of gas bubbles inside a downward flowing liquid. When the liquid moves slower than the upwards slip velocity of the gas bubbles the gas will rise to the top of the separator and may exit into the casing annulus. When the liquid moves faster than the rise velocity of the gas bubbles they will be dragged to the bottom and enter the dip tube that is connected to the pump intake.

Figure 9 shows a graph of experimental data related to the slip velocity of air bubbles in water as a function of the diameter of the bubbles. The figure shows that as the bubble size increases the slip velocity increases up to a limit. A given size bubble, say 2 inch diameter, has a slip velocity of 6 inches per second. Figure 10 shows three picture clips from a series of videos of the flow inside the separator in the vicinity of the entrance to the dip tube. When the liquid velocity is 5 inches per second, the dip tube is clearly visible since there are only very tiny bubbles being dragged by the downward liquid flow. When the liquid velocity is increased to 6 inches per second, a swarm of larger bubbles reaches the entrance to the dip tube but remain suspended in equilibrium and do not enter the dip tube. When the liquid velocity is increased to 9 inches per second the gas bubbles are dragged into the dip tube and into the pump intake. These figures were obtained while the liquid was flowing continuously at a constant rate. The next section discusses the mechanism for intermittent flow as exists in a reciprocating rod pump.

Pumping Cycle Simulation

Three bubble sizes have been chosen from Figure 9 for illustration of the cyclical flow that occurs in a rod pump system: 0.27, 0.7 and 2 cm diameter bubbles that have corresponding slip velocities of 1, 3 and 6 inch/sec respectively will be used to show their movement relative to the separator fluid intake and dip tube.

The simulation is based on the measured dynamometer data shown in Figure 11 for a rod pump operating at 6.95 SPM with 94% liquid fillage. Following are the details of the pumping system:

- Plunger Dia. 1.25 inch
- Plunger Area 1.227 sq.in.
- Pump Depth 10,540 feet
- 2 3/8" Collar Sized Gas Separator
- Area between Dip Tube and Barrel ID - OD 4.581 sq.in.

A total of 5 strokes are considered for a total duration of 39 seconds. Liquid velocity in the separator is computed based on the plunger velocity and plunger area. The figure shows the position of the liquid and of each size bubble as a function of time. The larger bubbles that exhibit a slip velocity of 3 and 6 inch/second enter the separator during the upstroke but also exit during the down stroke when the liquid velocity into the pump is zero. The smallest bubble size with a slip velocity of 1 inch per second enters the separator during the plunger upstroke but does not have sufficient slip velocity to rise to the top during the subsequent down stroke and thus progresses to the tip of the dip tube and enters the pump. (The PowerPoint simulation can be downloaded from www.echometer.com)

Field Performance of Separators

Figure 13 shows the performance of 3 ½ inch Collar Size Separators and Quinn Sand Screen Separators. The wells are approximately 10,000 feet deep and completed with 7 inch casing. A liner is present in the horizontal section of the wellbore. The separators are set at a depth of approximately 9300 feet. The producing bottomhole pressures were from 590 to 1300 psi. The tubing was 2 7/8 inch EUE. All wells had considerable fluid in the casing annulus above the pump. The casing pressure buildup rate varied from 0.3 to 1.5 psi per minute, and all wells contained several thousand feet of gaseous fluid columns in the casing annulus above the pump. The pump intake pressure varied from 440 to 1100 psi. A high pump intake pressure in a well producing oil and gas will result in a gaseous liquid column in the tubing.

The separator analysis shows a plot of the percentage of liquid in the pump compared to the percentage of liquid in the casing annulus. This is a good technique to determine separator performance. The Echometer Collar Size Separators are shown as diamonds and the Quinn Sand Screens are diamonds surrounded by a red circle. This data shows that most of the separators are performing well except for the one Quinn Sand Screen which has the same concentration of liquid in the pump as in the casing annulus. This data is available from info@echometer.com . Slawson Exploration Co., Inc.'s participation in this gas separator study is appreciated.

Collar Size Separator Capacity and Selection Guidelines

Table (3) presents information about liquid and gas capacity of the Collar Size separator based on a design liquid velocity of 6 inches per second [3] for the most common casing and tubing size configurations.

Table (4) presents guidelines for selection of the separator type[4] based on the desired liquid production rate and the measured increase in casing pressure recorded at the well during a fluid level measurement.

Conclusions

It is not difficult to properly design a downhole gas separator following the guidelines presented in this paper. Field data has shown that this design is vastly superior to the commonly used “Poor Boy” type separator assembled with piping available at the well site without consideration for the basic principles of separation mechanics:

- Limit liquid velocity to less than 6 inches per second by maximizing flow area inside the separator.
- Facilitate entry of liquid and evolution of gas by providing sufficient port area at the separator fluid intake.
- Minimize length of the dip tube and provide adequate diameter thin wall pipe.
- Limit gas velocity in the annulus by balancing the OD of the separator to the OD of the casing.

Separator performance should be checked frequently using fluid level and dynamometer measurements to monitor well performance.

Casing pressure buildup rate and Liquid Rate can be used to help select Gas Separator Type as shown in Table 4.

References

1. Brill, J.P., Caetano, E.F. and Shoham, O.: “Upward Vertical Two-Phase Flow through Annulus-Part 1: Single Phase Friction Factor, Taylor Bubble Velocity and Flow Pattern Prediction,” Journal of Energy Resources Technology, Vol. 114/1, March 1992.

2.Podio, A.L., McCoy J.N., Woods M.D., Nygard, Hanne, Drake B.: “Field and Laboratory Testing of a Decentralized Continuous-Flow Gas Anchor”. Presented at the 46th Annual Technical Meeting of the Petroleum Society of CIM, May 14-17, 1995.

3. J.N. McCoy, A.L. Podio, O. Lynn Rowlan, “Improved Downhole Gas Separator” SWPSC 1998.

4. McCoy, J. N. and O. Lynn Rowlan: “Downhole Gas Separator Selection”, ALRDC Gas Well Deliquification Workshop, Denver, Colorado, February 17 – 20, 2013

Tables

Gas Separator Capacity – Pump Below Fluid Entry Zone

Casing Size Inch	Dip Tube Size Inch	Description	Annulus Area* Sq Inch	Liquid Capacity BLPD
Conventional				
7	3 ½	Perforated Tubing Sub	23.1	1150
7	2 7/8	Perforated Tubing Sub	26.7	1335
7	2 3/8	Perforated Tubing Sub	28.8	1440
5 ½	2 7/8	Perforated Tubing Sub	12.7	635
5 ½	2 3/8	Perforated Tubing Sub	14.8	740
4 ½	2 7/8	Perforated Tubing Sub	6.1	305
4 ½	2 3/8		8.2	410
Higher Capacity if Needed				
5 ½	1 ½	Perforated Line Pipe	16.4	820
4 ½	1 ¼	Perforated Line Pipe	10.4	520

*Annulus Area Between Casing and Perforated Tubing Sub (or Line Pipe)

Table 1

GAS SEPARATOR CAPACITY TABLE
SEPARATOR ABOVE FLUID ENTRY ZONE

Outer Barrel Description and Size, Inch	Dip Tube Size Inch	Annulus Area SQ Inch	Liquid Capacity BPD
3 1/2 Perforated Tubing Sub	1.250	4.87	260
2 7/8 Perforated Tubing Sub	1.000	3.32	177
2 7/8 Perforated Tubing Sub	1.250	2.52	134
2 3/8 Perforated Tubing Sub	0.750	2.26	121
2 3/8 Perforated Tubing Sub	1.000	1.77	$\boxed{94}$
2 3/8 Perforated Tubing Sub	1.250	0.96	$\boxed{51}$
2 3/8 Perf Tub Sub & 1.5" Pump	1.760	0.69	$\boxed{37}$

Table 2- Liquid Capacity of "Poor Boy" Separator

Gas Separator - Gas and Liquid Capacity					
Tubing Size Inches	Collar O.D. Inches	Liquid Capacity Bbl/Day	Gas Capacity MCF/D @ 1 Atm of Pump Intake Pressure *		
			4 ½" Casing	5 ½" Casing	7" Casing
2 3/8	3.0	229	35	76	154
2 7/8	3.75	413	11	52	130
3 ½	4.5	624	-	23	101
4	5.0	778	-	-	79
4 ½	5.6	1016	-	-	49

* Multiply Gas Capacity times Pump Intake Pressure in Units of Atms.

Table 3 – Liquid and Gas Capacity of Collar Size Separators

Casing Size inches	Downhole Gas Separator Type	Pump Displacement or Production Rate BPD	Casing Pressure Buildup Rate psi/min
	Poor Boy 2 3/8 Perforated Sub	<50	<0.3 psi/min
4 1/2	2 3/8 Collar Sized (3.0" OD)	<200	any
5 1/2	2 3/8 Collar Sized (3.0" OD)	<200	<2 psi/min
5 1/2	2 7/8 Collar Sized (3.75" OD)	<400	<2 psi/min
5 1/2	3 1/2 Collar Sized (4.5" OD)	<600	<2 psi/min
5 1/2	Seating Nipple Separator	>50	>2 psi/min
7	2 3/8 Collar Sized (3.0" OD)	<200	<2 psi/min
7	2 7/8 Collar Sized (3.75" OD)	<400	<2 psi/min
7	3 1/2 Collar Sized (4.5" OD)	<600	<2 psi/min
7	Seating Nipple Separator	>100	>2 psi/min

Table 4 – Separator Type Selection Guidelines

Figures

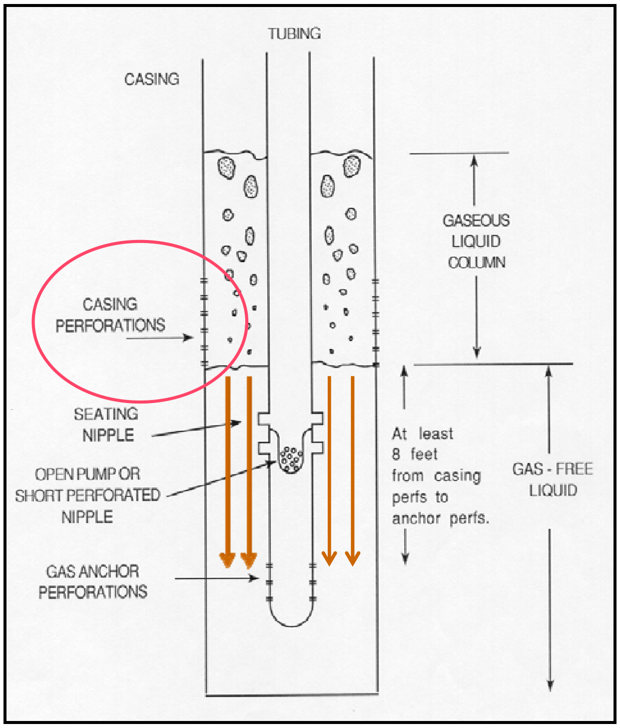


Figure 1 – Downhole Natural Gas Separator

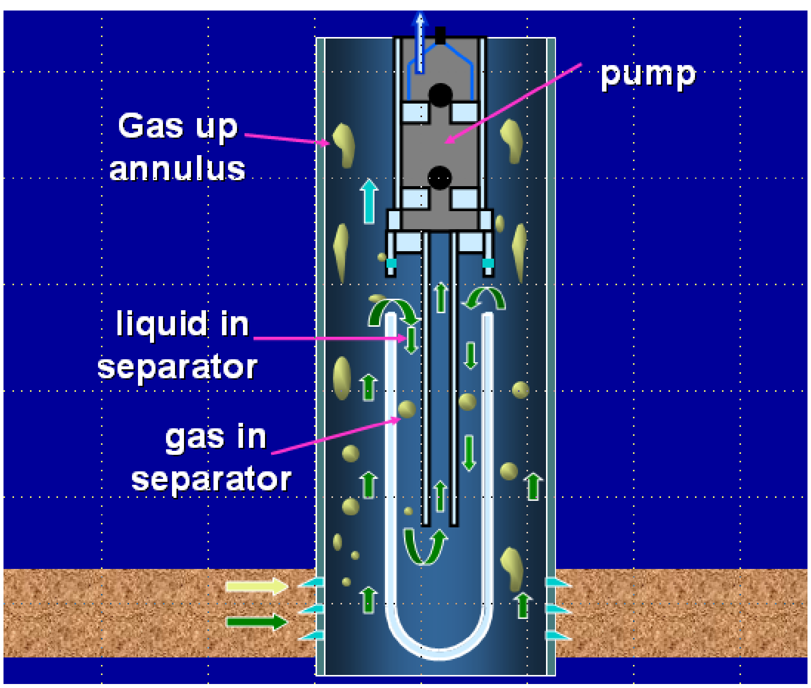


Figure 2 – Tubing Conveyed Down Hole Separator System

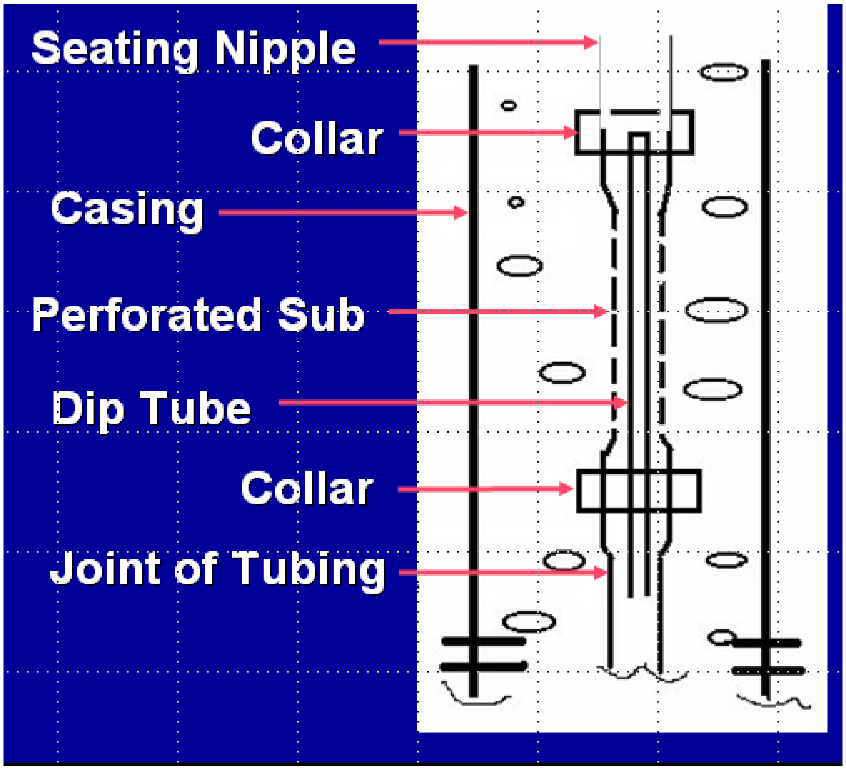


Figure 3 – Common Configuration of “Poor Boy” Gas Separator.

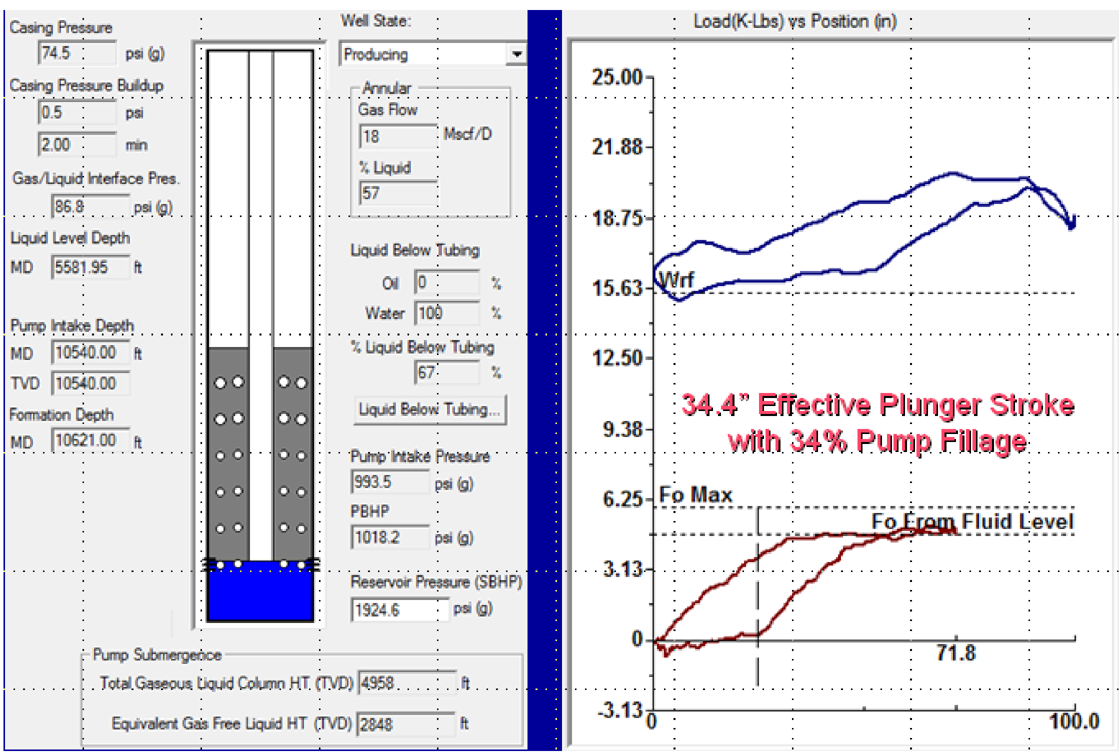


Figure 4 – Example Performance of Pump with “Poor Boy” Gas Separator

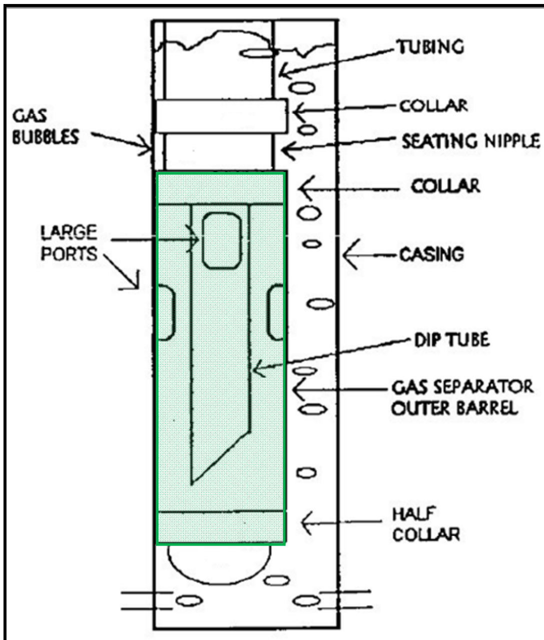


Fig. 5 Collar-Size Gas Separator in Casing

Collar Size Separator Eliminates Poor Boy Deficiencies

An efficient separator must balance annular flow area, separator flow area, dip tube diameter and pressure drop.

Outer barrel OD same as collar OD.

Thin short wall outer barrel and short dip tube.

Large inlet ports distributed around outer barrel facilitate entry of liquid.

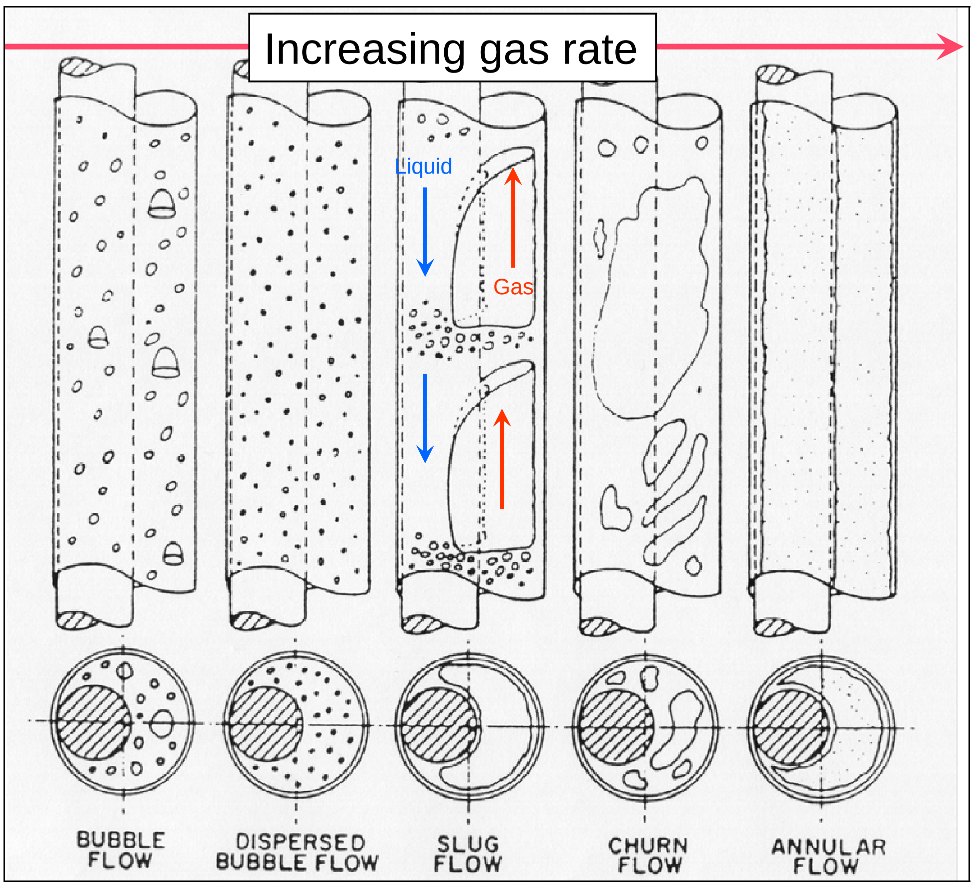
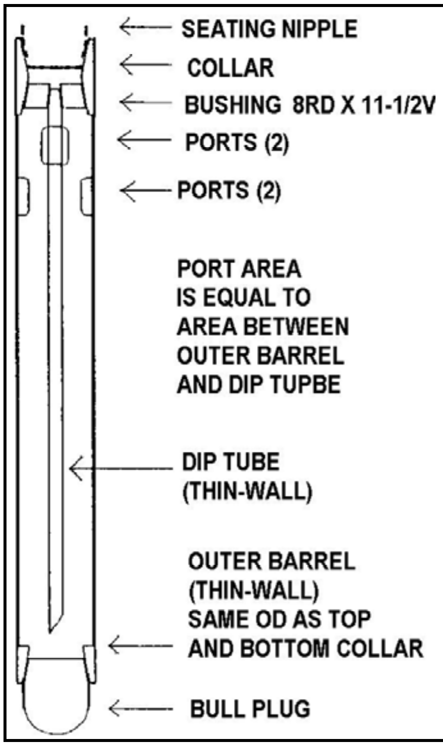


Figure 6 – Liquid and Gas Distribution for Vertical Flow in Eccentric Annulus (Ref 1)



Designed with thin-wall tubing, large ports and minimum lengths to optimize gas separation from the liquid that enters the pump.

Set 5.5 foot long separator 3 joints below tubing anchor.

OD of outer barrel of gas separator is the same OD as the tubing collar.

Collar at the top of separator attaches to bottom of pump seating nipple.

Optimum size dip tube is permanently mounted inside the outer barrel.

A bull plugged joint of tubing can be run below the bottom half-collar for a solids collection chamber if desired instead of the bull plug.

Figure 7 – Collar Sized Gas Separator Specifications

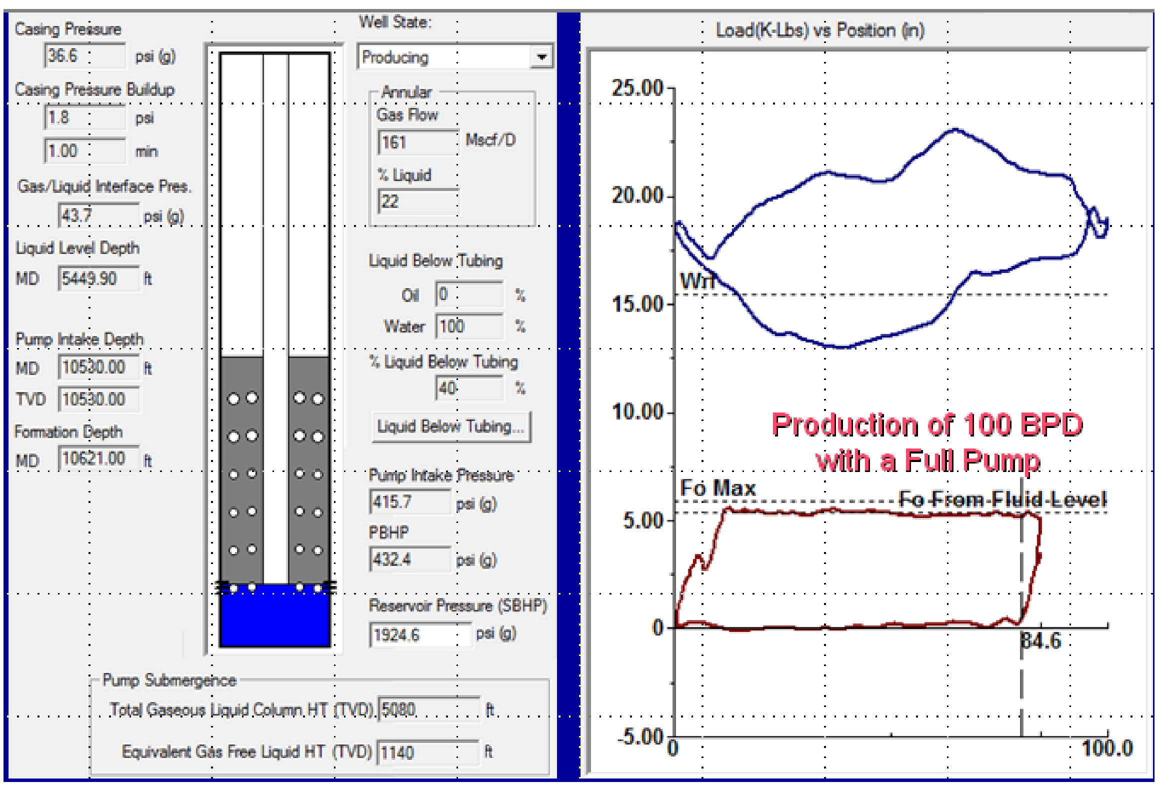


Figure 8- Pump Performance after Installation of Collar Size Separator in Well of Figure 4.

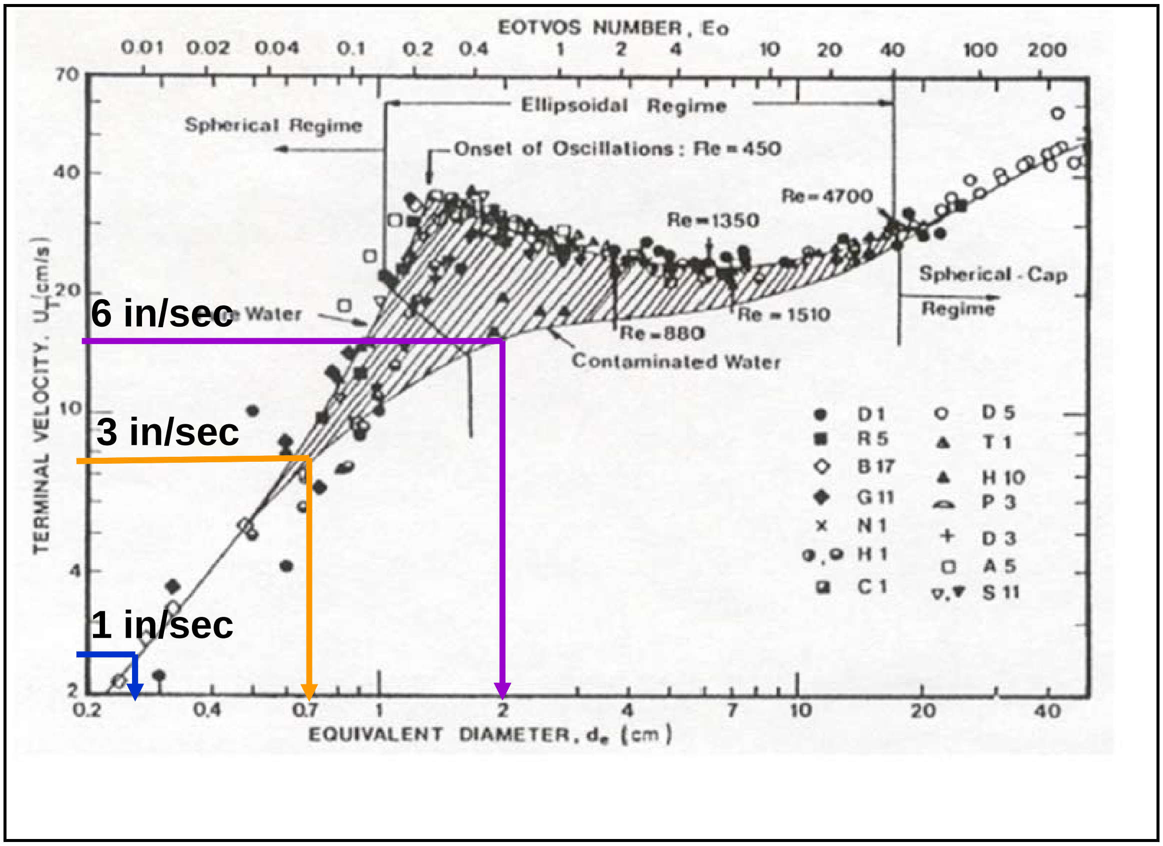


Figure 9 – Bubble Rise Velocity as Function of Bubble Diameter

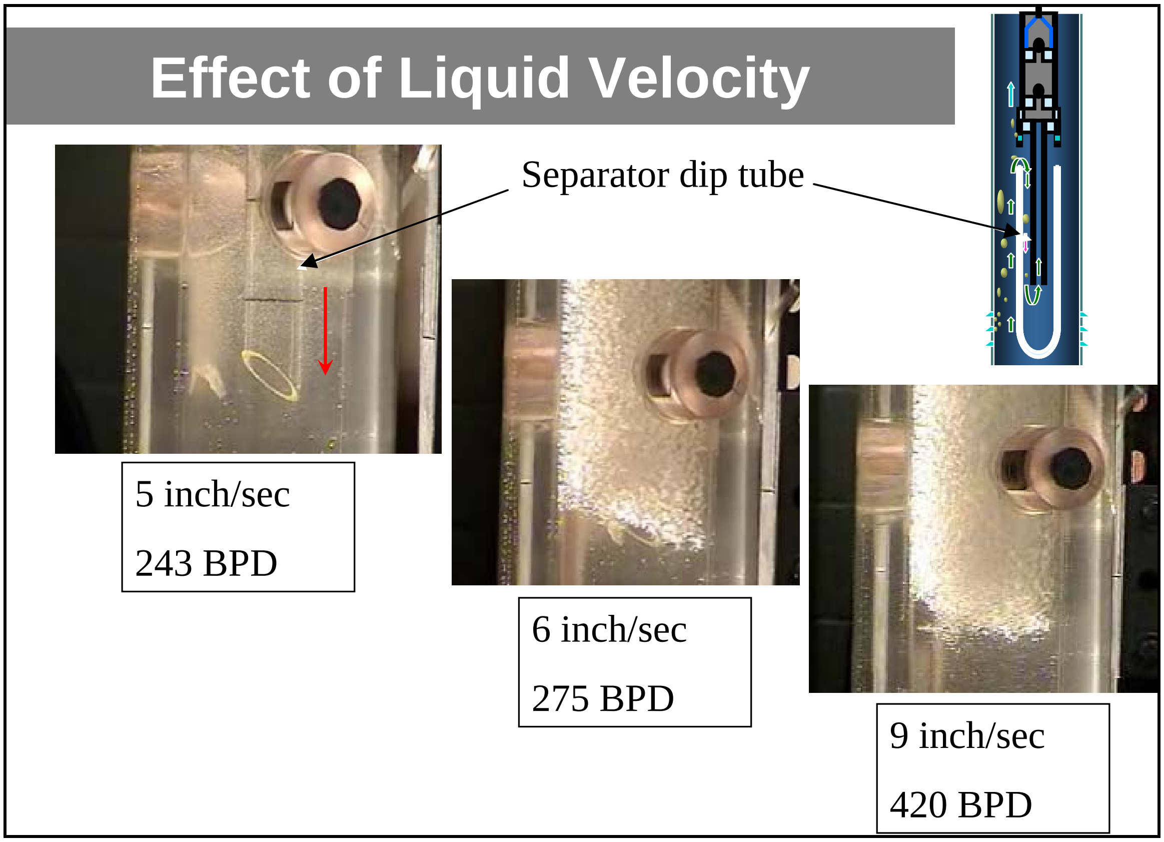


Figure 10 – Gas Flow into Pump Dependence on Liquid Velocity

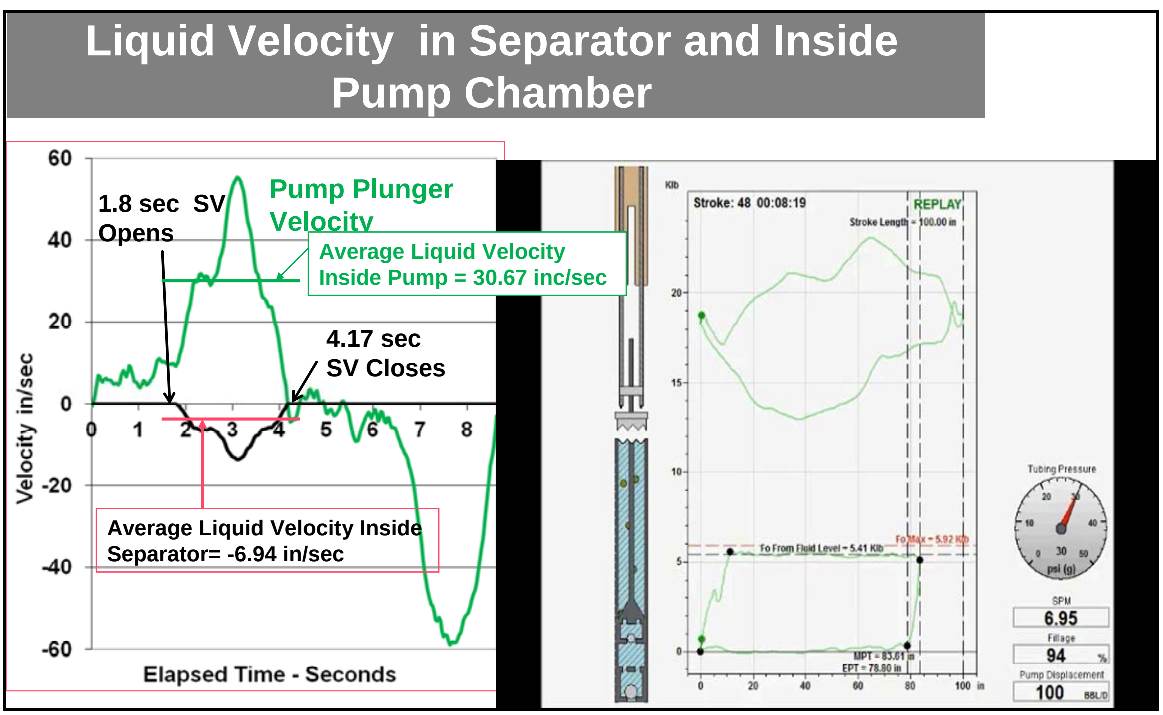


Figure 11 – Recorded Dynamometer Data for Simulation of Bubble Trajectories.

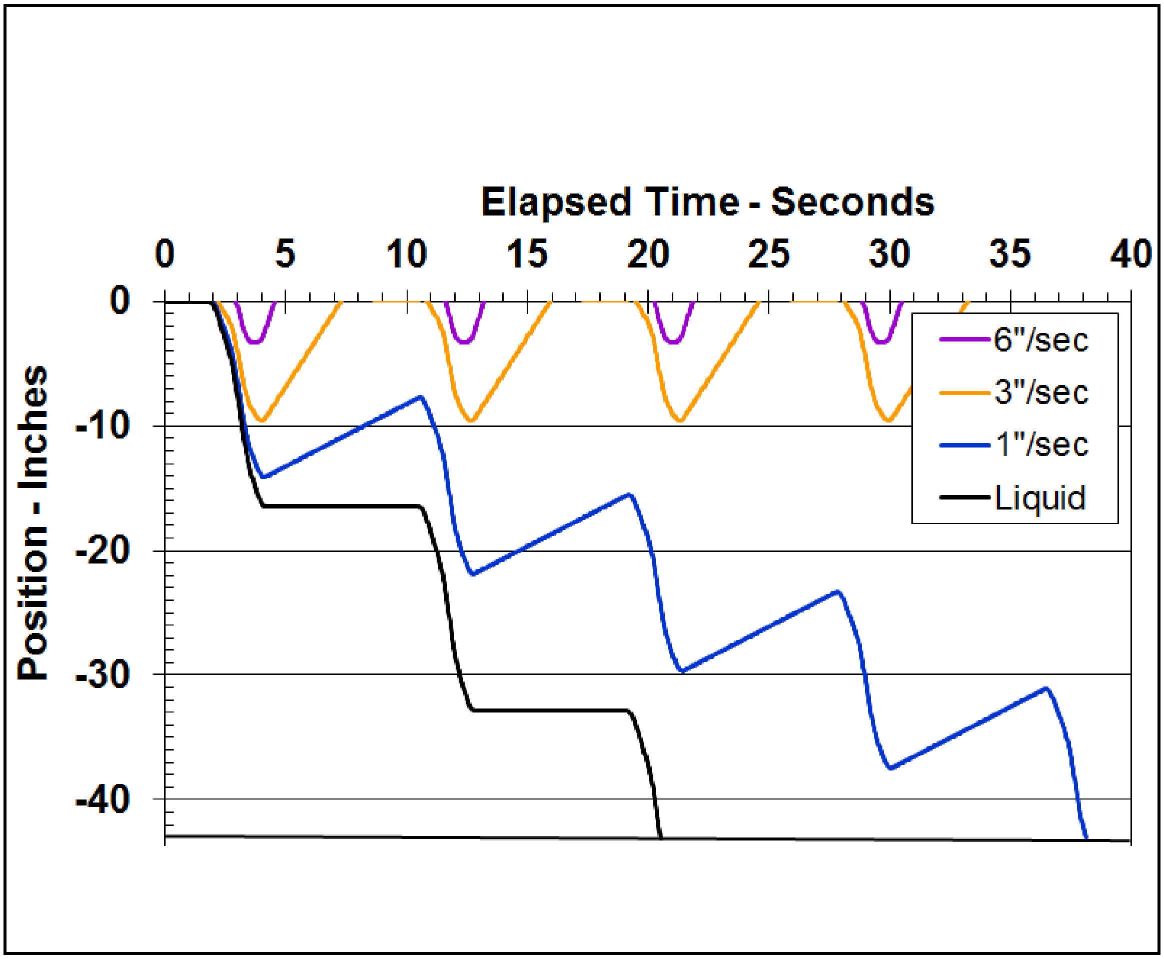


Figure 12 – Position of Bubbles of Different Rise Velocities inside Separator Annulus for Five Strokes of a 1.25 inch Pump Operating at 6.95 SPM.

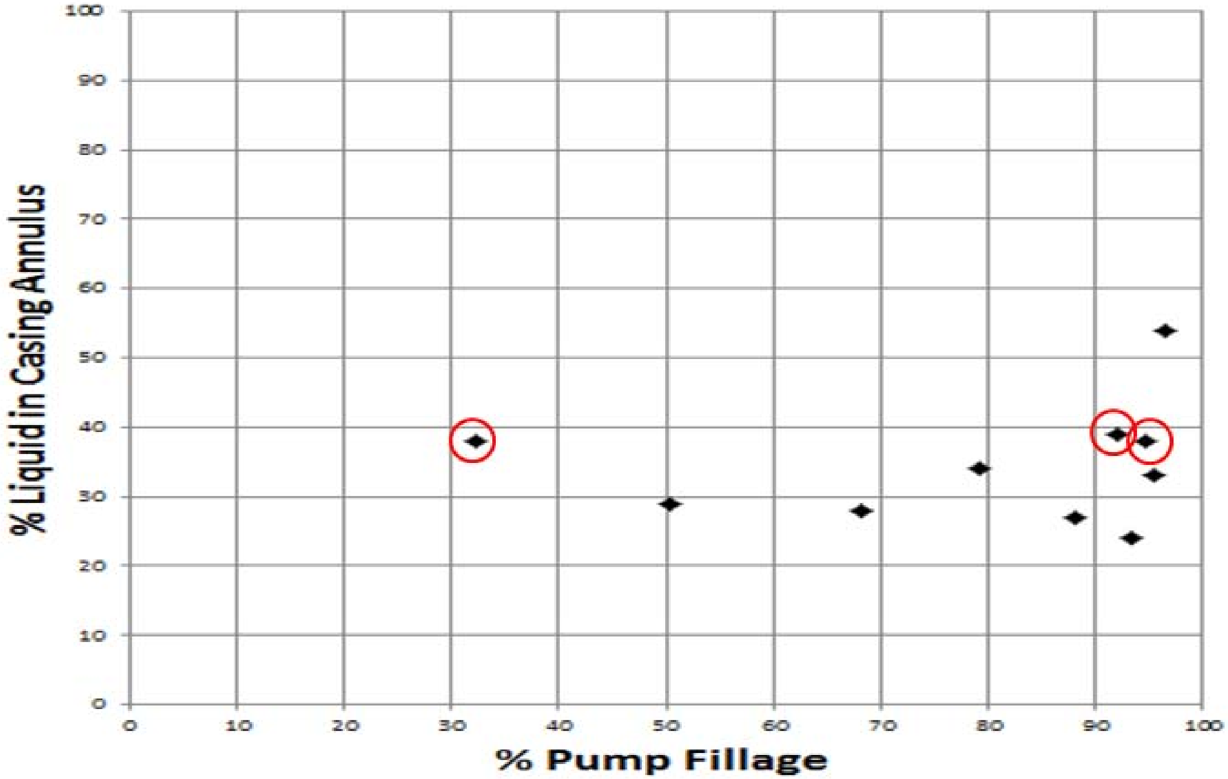


Figure 13 Performance of 7 Collar Size and 3 Quinn Sand Screen Separators