VISUALIZING ELECTRICAL SUBMERSIBLE PUMP (ESP) AND SUCKER ROD PUMP (SRP) GAS SEPARATION

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INTRODUCTION:

Two widely used methods of artificial lift are Electrical Submersible Pumps (ESP) and Sucker Rod Pumps (SRP. Each of these methods frequently require methods to avoid or handle gas for successful operations. Presented here are discussions of methods of gas separation for each method and graphical techniques for prediction of the gas separator performance that will allow the user to better select a workable gas separator system and predict maximum well drawdown with the selected method of lift.

'POOR BOY' SEPARATORS FOR SRP SYSTEMS:

If landing the pump above the perforations, one option to avoid gas interference is the Poor Boy separator, which creates conditions similar to the 'natural' separator described above.

The device consists of a mud anchor tube with a closed bottom and perforations at the top that allow fluid and gas mixtures to flow into the tube. A dip tube connected to the pump is mounted inside the mud anchor and extends downward, forcing fluid to flow down until it reaches the open end of the dip tube.

So long as the fluid velocity of the downward flow is less than ½' per second, gas bubbles will migrate upward into the annulus between the casing and tubing and not enter the dip tube. Therefore, the rated capacity of the separator is the fluid volume that achieves flow velocity of less than 1/2' per second.

Above the rated capacity, liquid flows downward too fast and will carry significant gas into the pump dip tube and into. A schematic is shown in Figure 1.

Poor Boy Rules of Thumb

The Poor Boy rules of thumb are:

The average downward velocity of the fluid in the down passage annulus between the downward facing intake dip tube and the separator ID should be as slow as is possible. Remembering that small bubbles get together and make big bubbles and big bubbles rise much faster, it should be obvious that the slower the downward velocity is and the greater the downward quiescent time, the better the gas separation will be. Test results indicate that the maximum downward design velocity should be about 6 inches/second based on the net cross sectional area, although this can be adjusted for special conditions.

For many years the rule of thumb has been for the quiescent volume, between the perforations in the tubing and the bottom of the suction tube, that it should be not less than and at least equal to 1-1/2 pump stroke displacements. The maximum volume should be about 2 pump stroke displacements. However more recently Echometer has applied engineering principles to this rule to fit what they have seen in laboratory experiments and have come up with the following formula for dip tube length (which gives a shorter dip tube length that historically used. See a schematic of the "poor boy" separator in Figure 1.

Dip Tube Length= Vb x 60/ (SPM x 2) x C
Example Calculation:
Vb (bubble rise velocity) normally 6 inches/second
SPM is strokes per minute
C: 1.233 for safety and velocity profile
For Vb =6 and SPM=5
The dip tube length= 6 x 60/ (5 x 2) x 1.233 = 44.4 inches

This value is typically much smaller than using 1.5 pump volume rule. Even when the average velocity of liquid through the separator is less than 6 in/sec, on the upstroke the gas moves down between the housing and the dip tube... If the dip tube is calculated according to the above formula, the gas will not move down pass the bottom end of the dip tube. This rule seems to model physically what is happening in the separator and gives separators that are shorter and more economical than using the old rule of thumb.

The reasons for these limits are that 1-1/2 pump stroke displacements will ensure that only quieted fluid will be drawn into the pump. However, if more than 2 volumes are present, the suction tube length will be longer than necessary and the pressure loss in this long suction tube will cause some additional gas breakout as the fluid is drawn into the pump.

Therefore, the dip tube, run below the pump, should be of sufficient ID so that friction loss within the dip tube is less than 2 psi.

The cross sectional area of the mud anchor perforations should equal 4 times the suction tube-mud anchor ID annulus. These openings should be as close to the seating nipple as possible. This permits the shortest possible suction tube length. Slots instead of round holes will give the maximum open flow area in the shortest possible length.

The suction tube diameter should be the same as the pipe thread opening in the standing valve or seating assembly. The suction tube perforations or slots should have a cross sectional area at least 4 times the cross sectional area of the suction tube ID. The bottom of the suction tube should be 'orange peel' welded closed so that paraffin cannot enter when the pump is being lowered through the tubing.

Mud anchor perforations or slots should never be located opposite the producing interval. The explosive turbulence in a producing interval is not conducive to good separator efficiency.

<u>A critical rule of thumb for Liquid Barrels per Day (BPD) Capacity</u>
For 1/2 ft/sec, the rate = 53.42 BPD/sq in. of annular space in the separator
Or, approximately
1/2 ft/second = 50 BPD/sq. in. annular space in the separator
This rule can be found from the following calculation:
Consider fluid passing through 1 square inch of area. How many Bpd corresponds to ½ ft/sec?
BPD/in^2 = A inch^2/144 inch^2/ft^2 x ½ ft/sec x (1/5.615 ft^3/bbl) x 24 x 3600 sec/day
=53.42 BPD/in^2 of area.
Example: The annular area (for example) between the housing ID and the dip tube OD is:
Annular Area=3.14*(2.44^2-1^2)/4 = 3.88 in^2 where housing ID is 2.44 and dip tube OD is 1 inch,
Then the maximum BPD capacity of this separator is 53.4 BPD/in^2 of down flow area x 3.88in^2 = 207 BPD

Multiply the annular area between housing ID and dip tube OD by 53.4 to get the BPD maximum production capacity of the poor boy separator. Some round to 50 to have a more memorable rule that is a little more conservative as well.

Collar-size Separator:Echometer manufactures a collar-size separator, which has a larger OD (matching the collar OD) and thinner walls, which allows higher liquid flow rates.

A gas separator made with standard tubing dimensions is limited to about 240 bpd for most cases. The collar size separator can achieve liquid rates of 200-600 bpd depending on the ID of the separator housing. The same rules as above apply but the dimensions are different.

See Echometer.com for details.

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

There are two constraints on gas separation with a poor boy separator.

The down flow velocity of the production must be <1/2 fps within the separator so the liquids will not carry bubbles down and not into the dip tube.

The casing gas flowing upward past the intake of the separator housing must be ~<10 fps to avoid mist flow. Mist flow does not allow time for separation in the housing of the separator. This 10 fps is only an approximation. Also it must be pressure dependent. One method of determining a boundary to mist flow is to use critical velocity. A simplified expression for the Turner critical velocity (with some estimates of properties is $V_{crit,water} = 5.31x(67 - .0031xP)^{.25}/(.0031xP)^{.5}$, fps. This will be used to calculate a velocity boundary for Mist Flow. The critical velocity is scaled to agree with Figure 13B-2 for the flow regimes of annular flow for the pressure indicated for the flow map.

The in-situ gas velocity can be calculated as below:

CF/Sec of gas up annulus = BOPD (GOR-Rs) (14.7/(PIP+14.7)) (1/Z) (520/((BHT+460)(Z))) (1/(24*3600) , CFS
Area= 3.14 ($CasID^2$- Housing OD^2)/ (4) , sq In
Ft/Sec of annulus gas =CFS/Area
Where:
Rs = solution GOR, scf/bblo
GOR = gas /oil ratio, scf/bblo
Z is gas compressibility factor
PIP= intake pressure
BHT = bottom hole temp, F

If these two constraints are both satisfied then the poor boy separator can perform as well as can be expected.

Visualization of Poor Boy Separator Performance

Performance of the gas separator is shown with reservoir performance in the following plots to see under what ranges of flow the separator can perform as designed.

Example of used of SRP Gas Separator

Rules: Several examples of use of the rules for the poor boy separator are presented. Three examples are discussed for low, medium and high gas are presented and discussed. The input for the reservoir (Vogel IPR) and the pump and separator situations are presented and discussed.

<u>Low Gas Case:</u>

The first case to be considered is labeled as low gas with a 500 scf/bblo GOR. All the data is shown below. The shut in pressure is 333 psi and the maximum liquids on the IPR are shown to be 268 bpd calculated and shown on the graphical results.

Test BOPD	111	Input
Test BWPD	111	Input
% Oil	90.0	Calc
Vogel Number	0.2	Input
Ptest, psig	111	Input
SIBHP, psi	333	Input
Gas Gravity	0.65	Input
BHT, F	160	Input
API	33	Input
GOR, scf/bopd	500	Input
Water Fraction	0.10	Calculated
Qtest,BFPD	222	Calculated
Qmax ,BFPD	267	Calculated
Pb, psi	181	Calculated
PI, bpd/psi	1.057	Calculated
SpGr Oil	0.86	Calculated

Poor Boy Single Point Calculation (uses GOR above)

Dip tube OD	1.01	Input
Housing ID	2.44	Input
Housing OD	2.875	Input from above
Downflow area sq in	3.87	Calculated
Allowable BPD	205.26	Calculated at 1/2 fps

In Figure 2, the downward velocity of the liquid in the separator is scaled for the plot to show as 100 when the calculated value is ½ fps. The in-situ gas velocity in the annulus is scaled on the plot to show 100 when it is calculated as 10 fps. This allows curves to show on the IPR which is developed with larger numbers.
In Figure 2, note that the liquid FPS on the plot reaches 100 (1/2 fps) when the rate is a little over 200 bfpd. However, the annular gas velocity does not reach the mist limit until the rate is well over 250 or so. So for this case the separator can be designed by checking the rate of liquid in the separator. The gas velocity in the annulus does not reach the limit for mist flow until after the maximum liquid velocity for liquid downflow through the separator is reached.

Note however the analysis above is for bubble rise of ½ ft/sec. UPS reports that for high oil cut wells in the Bakken, Permian or Delaware, the bubble rise can be ½ the value of ½ ft/sec or even lower. If for instance the bubble rise is ¼ ft/sec instead of ½ ft/sec then the limiting value on the chart would be 50 (for 200 x Vel in the separator) so the production could only go to ~100 bpd as an upper limit and production rates above this would not allow separation.

Medium Gas Case:

Input data is the same as for low gas case except the GOR is input as 5000 scf/bopd

Poor Boy Single Point Calculation (uses GOR above)

Dip tube OD	1.01	Input
Housing ID	2.44	Input
Housing OD	2.875	Input from above
Downflow area sq in	3.87	Calculated
Allowable BPD	205.26	Calculated at 1/2 fps

Graphical output for the "Medium Gas" case The first plot showed result for the low gas case or in this example the GOR=500 scf/bopd. The next case is for a higher input GOR (5000) and is labeled as the "medium gas" case.

The graphical output for the “medium gas” case is shown in Figure 3. The maximum allowable BPD is the same as for case one, 205.26. In this case the annular velocity of gas shows that the limit of mist flow is reached at about the same rate of liquid production.

Next the “High Gas” case is illustrated and discussed. The GOR is set at 10000 scf/bopd. The input data is as follows:

Poor Boy Single Point Calculation (uses GOR above)		
Dip tube OD	1.01	Input
Housing ID	2.44	Input
Housing OD	2.875	Input from above
Downflow area sq in	3.87	Calculated
Allowable BPD	205.26	Calculated at 1/2 fps

Figure 4.a shows the results of the “high gas” case. Again, the max rate for the ½ fps for the liquid in the separator is about 205 bfpd. However the annulus gas reached the mist flow limit about 125 bpd production. So in this case the allowable production is reduced by the annulus gas reaching a limit at a low production rate.

However Figure 4.b with the oil set at 10% and the same GOR (10000) shows no restriction in production with gas as the annulus gas is predicted to not flow in mist flow until the liquid downflow rate is past the ½ fps rate. So the separator has full range of operation not hindered by the limitation of the annulus gas possibly getting into mist flow.

It is recognized that most of the time an IPR is not available so the user will have to enter the producing BHP (perhaps from a fluid level shot analysis) and the production BPD to see if the equations indicate if the gas separator can be working as it could be or not. Below are a few examples using the same data as above but changing the pressure and temperature:

<u>Example One:</u>

The data is the same for the low gas case but the PIP is varied (GOR: 500 scfd/bopd)
BFPD: 205.46

PIP	Annulus Gas Velocity, fps	mist limit fps
50	12.85	22
100	2.14	16
200	1.11	12

<u>Example Two:</u>

The data is the same for the Mid Gas case but the PIP is varied (GOR: 5000 scfd/bopd)
BFPD: 205.46

PIP	Annulus Gas Velocity, fps	Mist Limit, fps
503	39.19	22.03
100	22.08	16.53
200	11.76	12.07

<u>Example Three:</u>

The data is the same for the High Gas case but the PIP is varied (GOR: 10,000 scfd/bopd)
BFPD: 205.46

PIP	Annulus Gas Velocity, fps	Mist limit, fps
50	78.45	22.03
100`	44.23	16.
200	23.5	12.07
300	16.07	9.96

This previous section shows ways to illustrate the effects of the downward produced fluids in the pump and the Produced gas velocity up the annulus. The produced fluids in the pump must travel downward slower than .5 fps so bubbles are not carried downward and into the dip tube and pump and the gas velocity must be less than 10 fps in the casing to avoid mist flow which restricts flow into the separator.

If the gas velocity up the annulus is too large then one solution could be as shown in Figure 5.
In Figure 5, on the left a pump set in the vertical is shown. The intake is set well above the lateral and kick off. On the right a packer gas separator is at the tubing bottom and a dip tube is extended to the near the lateral and the kick off giving a deeper location for the intake. Also the annulus gas does not cross by the separator intake as it would with a poor boy separator and as such this arrangement may be able to handle more gas than the poor boy. The intake of the separator is above the packer and immersed in a "pool" of liquid. Granted that with high gas rates, there could be significant mixing of gas and liquid that would have to separate in the down flow area from the end of the dip tube and the intake above the packer. However there are no specific problems that would restrict the entry of gas and liquid into the separator such as getting into mist flow in the casing/separator annulus does for the poor boy separator.

The dip tube would be sized such that it has stable flow and does not have too much friction in the dip tube flow. This can be done using conventional Nodal analysis techniques or by checking that the flow in the dip tube is above critical flow yet it is not as small as to have high friction losses.
See Figure 6 and Figure 7 for Nodal results obtained when comparing dip tube performance.

Data example:

Well data:

WHT: 100F WHP: 100 psi, BHT: 170F, GG: .65, Formation GOR: 3750, API: 35 WG: 1.00

Dip Tube Profile:

MD	TVD
200.0	200.0
400.0	387.9
600.0	541.1

<u>Results:</u>

1.995 from ~40 to 200 STPPD
3.92, 4.8 and 6.2 IDs all unstable up to at least 250 bpd
1.05, 1.38 and 1.61 stable above 20 bpd, 1.05 good down to about 15 bpd.
Around 15-60 bpd, 1.38 and 1.61 have pressure drop of about 20 psi
Above about 30 bpd friction makes 1.05 tubing have high pressure drops
The stable performance should make the gas separator work much better than unstable performance with casing flow to the packer separator.
Sand: Caution with sand, however there are at least 100 of these systems running in horizontal wells.

So would a system like this handle gassy situations where the annulus velocity is too high around a poor boy separator and this dip tube system would be more reliable? Echometer has some data to indicate it can be done. The gradient from the PIP to the lateral can be reduced from about .38 psi/ft to perhaps .11 psi/ft with subsequent reductions in the producing pressure on the formation.
Also it should be mentioned that some using FG rods and guided steel on bottom are able to set the pump deep.

Free Gas and ESP Operation and Performance

Introduction:

Free gas can be very detrimental to ESP lift performance causing the pump head to become degraded[1] which causes the pump intake pressure (Pip) to increase, increasing the well's producing pressure, which reduces the production rate. If the percentage of free gas becomes high enough in the pump stage then the head produced by the stage will be degraded to zero, which leads to the pump rate dropping to zero and the pump is gas locked.

When the pump becomes gas locked, the fluid from the reservoir begins rising above the ESP and accumulates in the casing tubing annulus which increases the producing pressure, which slowly reduces the fluid rate from the reservoir.

In the typical ESP installation, the ESP intake is set above the producing interval, so that the produced liquids provide the cooling for the ESP motor. When the ESP is gas locked the reduction of the cooling liquids over time will increase the motor operating temperature and can lead to a motor failure.

There are 2 methods for providing motor protection in this gas locked pump condition.

1. The motor controller or Variable Speed Drive (VSD) monitors the motor amperage and determines there is an underload condition when the operating amperage drops by 10 to 15 percent. The motor amperage is proportional to load and in the gas locked condition the pump load is reduced to only the internal losses in the stage since no fluid is being lifted. When the drop in operating amperage occurs, the controller shuts the ESP down.
2. A restive temperature device (RTD) or a thermocouple is embedded in the motor windings. The RTD is connected to a downhole sensor attached to the bottom of the motor which is connected to the three phase power. The sensor transmits the motor temperature to a surface readout over the three phase power cable, which in turn passes the temperature to the motor controller or VSD. The temperature can then be compared to preset values that determine the controller's response. The Switchboard motor controller will respond by shutting the ESP down once the temperature rises to the entered, maximum allowed, temperature value. The VSD controller may have an operating routine that adjusts the frequency, up and/or down to break the gas lock. If it is unsuccessful, and the motor temperature continues to rise, then the routine will also shut down the ESP.

In either of the above methods, once the ESP is shutdown it can restart automatically after an appropriate period to allow the well and pump to recover from the gas lock condition. Usually the minimum time would be 45 minutes to an hour. This allows the fluid in the tubing, that is falling back through the pump, to stabilize and stop rotating the pump backwards. Starting the ESP when the pump is rotating backwards can lead to the shaft breaking. A check valve above the ESP can prevent backwards rotation but may introduce other operational problems.

Since the ESP is being turned on and off because of the free gas interference, the well is not producing to its maximum potential and revenue is lost.

Determining Pump Performance versus Free Gas Percentages:

The first step for determining the best method for avoiding or handling gas interference is to determine the amount of free gas the ***pump*** can handle without head degradation or gas locking. There are 2 correlations for predicting head degradation and gas locking.

1. Turpin's Correlation [2] uses the in situ flow rates through the stage at the Pip and temperature to calculate a correlation constant (PHI). When PHI is less than one, pump gas locking is not predicted. When PHI is greater than one, gas locking is predicted.

$$\Phi = \frac{667}{\mathrm{Pip}} \times \frac{bgpd}{bopd + bwpd} = \frac{667}{\mathrm{Pip}} \times \frac{GVF}{1 - GVF}$$

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. See figure 8.

$$\mathrm{Pip} = 667 \times \frac{GVF}{1-GVF}$$

For any given GVF, the further the pump intake pressure drops below the curve the higher the probability of gas locking the pump.

2. Dunbar's Correlation[3] 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. See figure 9.

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

For any given GVF, the further the pump intake pressure drops below the curve the higher the probability of head degradation in the pump and eventually gas locking.

Using the two correlations in Figure 10 as a guide and looking at a GVF of 0.15 into the pump (15% free gas by volume), the minimum Pip for no gas interference would be 340 psi. The stage head performance would be degraded from a Pip of 340 psi down to 120 psi and below 120 psi the stage would likely gas lock.
Remember this is the GVF ***after*** any natural or mechanical separation.
When the Dunbar correlation begins to predict head degradation, adding additional stages (over staging) and / or the use of a tapered pump may allow continued production at pressures below the Dunbar critical pressure and the addition of a gas handler may allow for operating pressures below the Turpin critical pressure for gas locking.

Methods for Keeping the Free Gas from Entering the ESP:

- **Natural Separation with Intake Above the Producing Interval – intake vertical**

Natural separation can be estimated using Alhanati's [4] gas separation efficiency correlation.

$$E = \frac{V_t}{V_t + V_{sl}}$$

Where;

E = Efficiency of natural separation, fraction
Vsl = Superficial velocity of the liquid phase, ft/sec
Vt = Terminal bubble rise velocity, ft/sec

And

$$V_t = 0.79 \times \sqrt[4]{\frac{\sigma_l\left(\rho_l - \rho_g\right)}{\rho_l^2}}$$

Where;
σ_l = interfacial tension, dyne/cm
ρ_l = liquid density, lb/cu ft
ρ_g = gas density, lb/cu ft

Gas moving through a water and/or oil mixture will usually have a terminal velocity (V_t) of about 0.5 ft/sec[5]. Superficial liquid velocity (V_{sl}) can be found by calculating the flow area, given the ESP intake O.D. and the casing I.D. and then determining the velocity using the in-situ oil and water production rate at the intake.

$$V_{sl} = \frac{BLPD_{isc} * 5.61458 \frac{ft^3}{bbl}}{24 \frac{hrs}{day} * 3600 \frac{\sec}{hr}} * \frac{144 \frac{in^2}{ft^2}}{\frac{\pi}{4} * \left[\left(\text{CasingID in}\right)^2 - \left(IntakeOD\ in\right)^2\right]}$$

Setting V_t = 0.5, the efficiency vs V_{sl} can be plotted as shown in Figure 11.

For selected Casing ID and pump intake OD the estimated natural separation efficiency can be calculated and plotted against the in situ production rated as shown in Figure 12.

At 3000 $BLPD_{\text{in situ}}$, in 5.5", 20 Lb casing with a 4" intake the natural separation would be less than 10%.

Alhanati's [4] gas separation efficiency correlation works well when the vertical Flow Pattern is Bubble flow. Slug, Churn, Annular and Mist flow make predicting natural separation impossible. Single phase liquid flow and bubble flow are ideal for ESP operation. Slug flow will cause erratic pump operation with gas interference and locking for natural and mechanical separation. See the Flow Patterns in Vertical Flow Figures 13A-1 and 13A-2 and 13B-1 and 13B-2.

Assuming an eccentric annulus and by isolating Vsl from 0.01ft/sec (0.003 m/s) to 10 ft/s (3.0 m/s) and Vsg from 0.01 ft/s (0.003 m/s) to 3 ft/s (0.915 m/s), the bubble flow / slug flow interface can be plotted in terms of BLPD vs GVF. See Appendix B for the Vsl to BLPD conversion. The plot in figure 14, turns superficial liquid velocity (Vsl) and superficial gas velocity (Vsg) into BLPD vs GVF for 5.5", 20lb casing and a 4" OD intake and a 3.38" intake.

Using the graph for a 4" OD intake in 5-1/2", 20# casing at a flow rate of 1000 in situ BLPD, the maximum GVF should be no higher than 0.29 (29% free gas by volume) for bubble flow at the intake.
Using a 3.38" intake will increase the allowable GVF to 0.33 (33 % free gas by volume) at 1000 BLPD.

- **Natural Separation with Intake Above the Producing Interval – intake inclined or Horizontal**

Below are the two phase flow patterns (figure 15A) and flow regime map (figure 15B) for horizontal pipes[7].
These flow patterns would lend themselves to an intake that can use gravity to automatically adjust so that the intake ports are on the bottom. This paper does not address gas avoidance for ESPs set in the

horizontal section of the well. There are bottom feeder intakes available from the ESP manufactures and third party suppliers.

- **Intake below the producing interval with motor shroud**

Ideally the gas will be separated at the producing interval and only liquid will enter the ESP. The ESP motor is cooled by the produced fluid. This is the reason that most ESPs are installed above the producing interval. If the casing is large enough and the ESP motor and seals are small enough, the Pump intake, seal(s) and motor(s) may be shrouded, and the unit may be set below the producing interval. The produced fluid must travel down past the pumps and shroud and then back up between the motor and shroud to get to the pump intake. Allowing the produced fluid to cool the motor.

- **Intake below the producing interval with motor recirculation system**

This system uses a recirculation pump to pump part of the produced fluid past the motor for cooling. The pump may be part of the pump assembly or it may be a pump on the bottom of the motor. The recirculating system will allow the ESP to be placed below the production interval when a shrouded unit would not fit. Ideally the gas will be separated at the producing interval and only liquid will enter the ESP.

- **Intake Above the Production Interval - Motor Shrouded Intake or ESP Pod with a Tail pipe or Dip Tube:**

This system uses a tail pipe (or Dip tube) so that the liquid is drawn into the pump from below the producing interval. Ideally the gas will be separated at the producing interval and only liquid will enter the ESP through the tail pipe.

- **Intake Below the Production Interval – PMM without Cooling**

At this writing, this author is familiar with only one test installation using a PMM below the production interval without a shroud. [8] While the test case was a success, the authors of the paper also noted the need for additional modeling information for the estimation of PMM heat rise and more test cases.

- **Inverted Shroud with Intake Above the Producing Interval**

The ESP is above the producing interval, but the intake and pump are shrouded such that the produced liquids must pass up between the shroud and casing and then fall back into the annular area between the shroud and tubing and then between the shroud and pump to get to the pump intake.

- **Separation theory for the above ESP placement methods and shrouding:**

As mentioned earlier, Gas moving through a water and/or oil mixture will usually have a terminal rise velocity (V_t) of 0.5 ft/sec[5]. Superficial liquid velocity (V_{sl}) can be found by calculating the area given the ESP intake OD and the casing ID and then determining the velocity using the in-situ oil and water production rate at the intake.

In any of the above cases where the intake to the pump is located below the producing interval, the superficial liquid velocity (V_{sl})moving down toward the intake must be less than the terminal bubble rise velocity of 0.5 feet per second for the gas liquid separation to occur. As the V_{sl} increases above 0.5 feet per second the percentage of gas separation is reduced until it is finally zero. This author has not found any published data that defines the percentage of separation in terms of increasing V_{sl} above 0.5 feet per second. The most conservative view would be to assume the separation efficiency is 100% when V_{sl} is less than 0.5 feet per second and 0% when the V_{sl} is equal to or greater than 0.5 feet per second.

- **Intake Above the Production Interval using a Vortex Gas Separator**

The Vortex Gas Separator uses centrifugal force to separate the fluids according to the fluid density. The denser, (high specific gravity) fluids are forced against the separator wall and lighter, (low specific gravity) fluids, are left around the shaft. The vortex separator creates a vortex in the separation chamber with a spinning paddle set above the inducer or high angle vane auger. Figure 15, below, gives a general idea of liquid through-put vs. percent free gas that can be separated. The vortex separator is designed to pull all the produced oil, water and gas into the vortex chamber where the gas and liquids are separated.

As an example, using figure 16, at a 4000 BLPD flow rate, the Hypothetical separator would be 100% efficient up to a GVF of 0.28. From a GVF above 0.28 up to a GVF of 0.39, the separation efficiency goes from 100% down to 0%. Above a GVF of 0.39, the separation becomes erratic and unpredictable and is labeled as 0% efficient.

The mechanical separator has a maximum fluid (oil, water, and gas) rate just as a pump has a maximum fluid rate where it produces zero head. When the flow (oil, water and gas) from the producing interval becomes greater than maximum intake rate, some of the oil, water or gas will remain in the annulus. If gas does not enter the intake then natural separation is occurring which would be ideal. However, this is not the likely scenario. At any moment, the intake may ingest more of the gas and leave some of the liquid in the annulus. Two things are happening in this scenario. First, the separation efficiency at this high rate is close to zero and gas will enter the pump. This change in the density in the pump will cause the motor amps to fluctuate as seen in the amp chart in figure 17.

When the pump intake pressure gets low enough, the GVF into the pump increases, decreasing the motor loading, and the GVF in the annulus decreases so that more of the liquid accumulates in the annulus. This begins to increase the Pip which decreases the GVF which then allows for a reduced GVF into the pump and increased liquid which shows up as increased loading on the motor. It can be a self-regulating system. However, the system can become unstable if the pump capacity is increased by increasing the operating frequency or reducing the tubing head pressure. This will decrease the average Pip and increase the GVF into the pump for longer periods of time which will eventually lead to a gas locked pump and a system shutdown.

Methods for Handling the Free Gas in the pump:

This paper is focused on gas avoidance and does not address design measures for handling the free gas should it enter the pump.

Below is a list of methods that may be employed at the design stage to handle free gas in the pump.

- Pump Radial flow vs Mixed flow stage design
- Gas Handler and Advanced Gas Handler Stage Design
- Pump Gas Handler Helico-axial Stage design:
- Tapered Pump Design
- Variable Speed Drive
- Tubing Head Pressure

A complete description for designing an ESP pump to handle gas can be found in *Gas well Deliquification, Third Edition,* (2019), pages 292 – 305[9].

Using GVF to predict Pump /Separator Performance;

Example 1

11,000' of 5.5", 20lb/ft casing, ID = 4.778"

10,100' = Top of the Production Interval (TPI)

10,057' = Pump Intake Depth

10,057' of 2.875", 6.5 lb/ft Tubing, ID = 2.441"

(Actual tubing length is the pump intake depth – the length of the pumps)

192 bopd, 873 bwpd, 464 mscfpd, Flowing

44^{o} API, Spg Gas = 0.83, Spg water = 1.03, Bubble point = 5,336 psi

Static Reservoir Pressure = 3500 psi

Producing pressure (Pwf) = 2800 psi

Reservoir Temp = 166^{o} F

Reservoir temperature = 166^{o} F

Proposed Pump Intake Diameter = 4"

Tubing Head Pressure = 200 psi

Casing pressure = 200psi

In situ flow for the oil and water and in situ flow for the oil and water and gas vs pump intake pressure are shown in figure 18.

Figure 19 shows the well in situ liquid flow vs GVF and with the bubble flow – slug flow boundary for a 4" intake and 5.5", 20#/ft casing. Remember this graph is specifically for 5.5", 20#/' casing with a 4" intake.

Figure 20 shows the well in situ flow with hypothetical 4" vortex separator curves for 100% and 0% separation efficiency vs GVF.

Example 2 – Increased Casing ID at Pump Intake Depth
<u>11,000' of 7", 33.7 lb/ft casing, ID = 6.765"</u> - the only change from example 1
10,100' = Top of the Production Interval (TPI)
10,057' = Pump Intake Depth
10,057' of 2.875", 6.5 lb/ft Tubing, ID = 2.441"
(Actual tubing length is the pump intake depth – the length of the pumps)
192 bopd, 873 bwpd, 464 mscfpd, Flowing
44^o API, Spg Gas = 0.83, Spg water = 1.03, Bubble point = 5,336 psi
Static Reservoir Pressure = 3500 psi
Producing pressure (Pwf) = 2800 psi
Reservoir Temp = 166^o F
Reservoir temperature = 166^o F
Proposed Pump Intake Diameter = 4"
Tubing Head Pressure = 200 psi, Casing pressure = 200psi
Figure 21 shows the improved natural separation efficiency as compared to the 5.5" casing in figure12.

The larger annular area using the 7" casing has moved the bubble flow to slug flow transition to 3000 BLPD vs the 2500 BLPD with the 5.5" casing for this example 2 case. See Figure 22.
Figure 23 shows the well in situ flow with hypothetical 4" vortex separator curves for 100% and 0% separation efficiency vs GVF for example 2.

Tandem Separator Performance.
Placing a second or third gas separator in tandem can improve the separation efficiency. The first (or lower tandem) separator must be operating below the 0% separation line otherwise the second (or upper tandem) separator will also be operating below the 0% separation line and total separation will be 0%. As an example, assume the gas rate at intake conditions is 2769 bgpd and the liquid rate at intake conditions is 3000 blpd

$$GVF = \frac{bgpd}{bgpd + blpd} = \frac{2769}{2769 + 3000} = 0.48$$

Using the hypothetical 4" vortex separator curves, the estimated separation efficiency is 29%. See figure 24.
The GVF into the second or upper tandem separator can be calculated as follows.

$$\text{bgpd}_{\text{after separation}} = \text{bgpd}_{\text{before separation}} * \left(\text{1-separation efficiency fraction}\right)$$

$$\text{2769 bgpd * (1- 0.29) = 1966 bgpd}$$

$$\text{GVF} = \frac{\text{1966 bgpd}}{\text{1966 bgpd + 3000 blpd}} = 0.396$$

Using the GVF of .396 and the liquid flow rate of 3000 blpd, the estimated separation efficiency for the upper tandem separator is 95%. See figure 25.

The overall separation efficiency is calculated as follows.

$$\text{Overall Separation Efficiency Fraction} = \left[1 - \begin{pmatrix} (\text{1-lower tandem separator efficieny fraction}) \\ *(\text{1-upper tandem separator efficieny fraction}) \end{pmatrix}\right]$$

$$\text{Overall Separation Efficiency Fraction} = \left[1 - (1\text{-}0.29)*(1\text{-}.95)\right] = .9645 \text{ or } 96.45\%$$

Conclusions;

1. Develop the well inflow curve and plot liquid flow and total flow vs pump intake pressure and temperature using the appropriate correlations or PVT data.
2. Use the inflow information to plot liquid flow vs GVF for the well. (Ql vs GVF plot)
3. Based on the ESP intake OD and the casing ID plot the bubble flow – slug flow boundary into the well liquid flow vs GVF (Ql vs GVF plot) and select an operating point at an operating liquid rate and corresponding GVF that will maintain bubble flow.
4. Estimate the GVF into the pump
    a. If there is no mechanical separator (Vortex Separator), then the natural separation should be estimated using Alhanati's correlation to determine the estimated separation efficiency.
    b. With mechanical separation, then plot the separator efficiency curves into the well liquid flow vs GVF (Ql vs GVF plot) and determine the estimated separation efficiency. If tandem separators are used then repeat the separation calculation until maximum separation is reached.
    Note: When a mechanical separator is used the natural separation efficiency should be set to zero. When operating correctly all the oil, water and gas are drawn into the separator intake. Hence zero natural separation.
5. Use the separation efficiency to determine the GVF into the pump.
6. Use Dunbar and Turpin's correlations to determine if stage head degradation or gas locking might occur in the pump.
7. Additional adjustments based on the Dunbar and Turpin correlations;
    a. Dunbar should be less than one for best performance.
    b. If Dunbar is greater than one, but Turpin is less than one, then 10% to 15 % additional stages should be added to the design. If it is a tapered pump design the stages should be added to the intake pump and the discharge pump.
    c. If Turpin is greater than one then the pump intake pressure (Pip) should be increased until Turpin is less than one. Then check Dunbar to see if stages should be added or increase the Pip again until the Dunbar correlation is greater than one.

Appendix A _ Correlations Used in the Calculations for the example problems.

Dead Oil Viscosity	Beal (1946)
Saturated Oil Viscosity	Beggs & Robinson (1975)
Under-Saturated Oil Viscosity	Vázquez & Beggs
Gas Viscosity	Standing (1981)
Water Viscosity	McCain (1988)
Oil Density	Standing (1981)
Pb/Rs	Al-Shammasi (1999)
Oil Compressibility	Vázquez & Beggs
Factor Z	Papay (1985)
Volumetric Factor of Oil	Al-Shammasi (1999)
Volumetric Factor of Water	McCain (1988)
Primary Flowing Gradient	Hagedorn-Brown

$$V_{sl} = \frac{BLPD_{isc} * 5.61458 \frac{ft^3}{bbl}}{24 \frac{hrs}{day} * 3600 \frac{\sec}{hr}} * \frac{144 \frac{in^2}{ft^2}}{\frac{\pi}{4} * \left[(TubingID\ in)^2 - (IntakeOD\ in)^2 \right]}$$

$$BLPD_{isc} = \frac{V_{sl} * 24 \frac{hrs}{day} * 3600 \frac{\sec}{hr}}{5.61458 \frac{ft^3}{bbl}} * \frac{\frac{\pi}{4} * \left[(TubingID\ in)^2 - (IntakeOD\ in)^2 \right]}{144 \frac{in^2}{ft^2}}$$

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1.Lea, J. F., & Bearden, J. L. (1982, December 1). Effect of Gaseous Fluids on Submersible Pump Performance. Society of Petroleum Engineers. doi:10.2118/9218-PA

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Table 1: Capacity of the Echometer Collar Sized Separator

Dip Tube OD	Sep Tube OD	Sep Tube ID	Annular Area in^2	Liquid Capacity BPD
1.315	3	2.75	4.6	229
1.315	3.75	3.5	8.3	413
1.5	4.5	4.26	12.5	624
1.66	5	4.75	15.6	778
1.66	5.6	5.35	20.3	1016

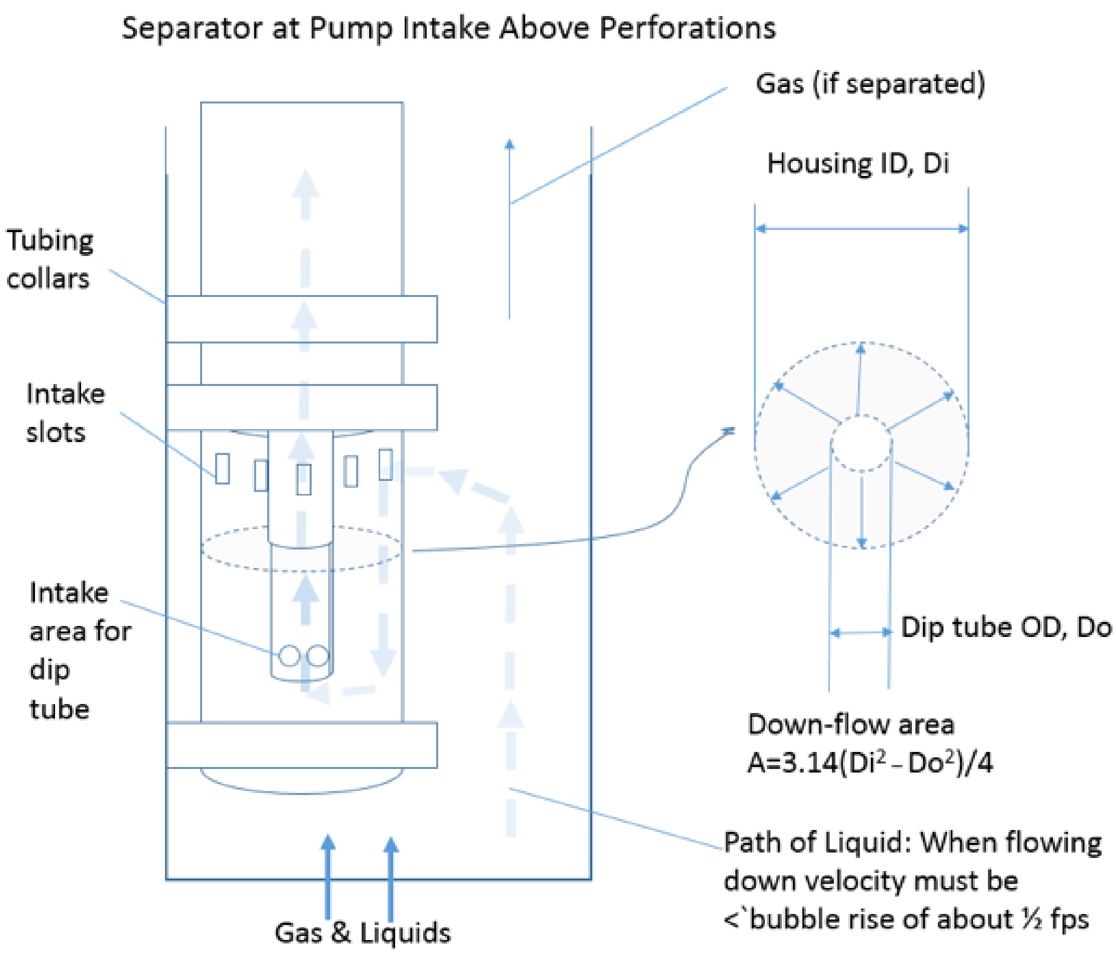


Figure 1: A schematic of the "poor boy" gas separator

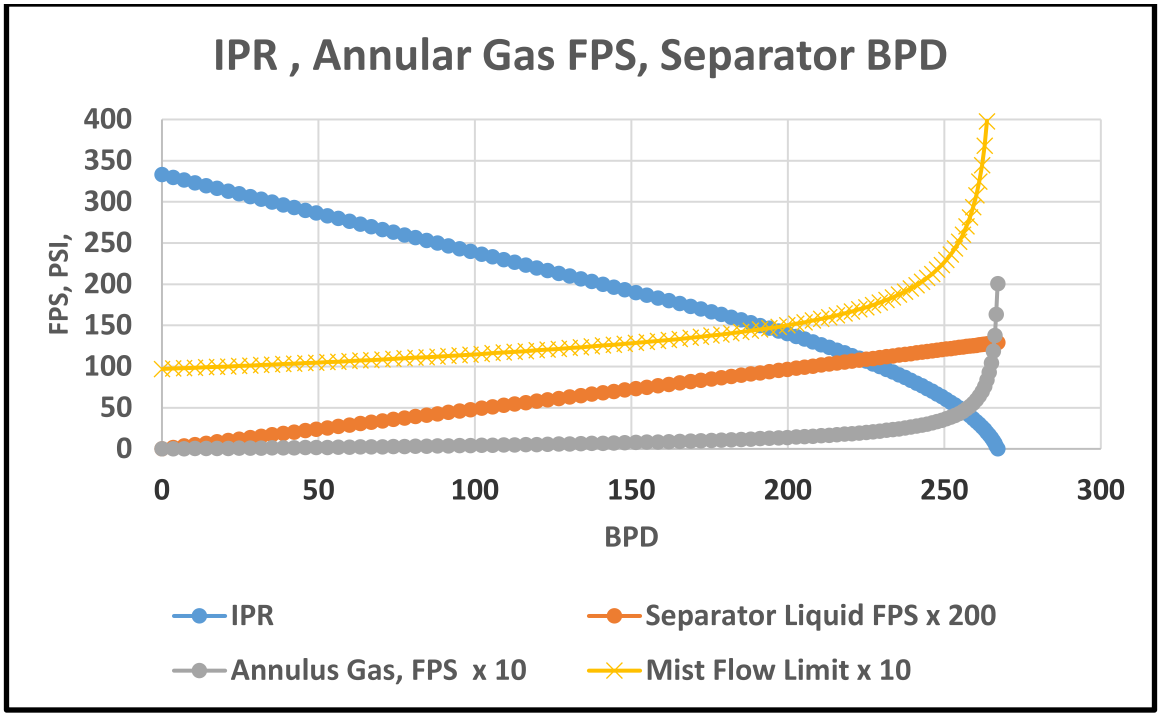


Figure 2: Results of the “low gas case”

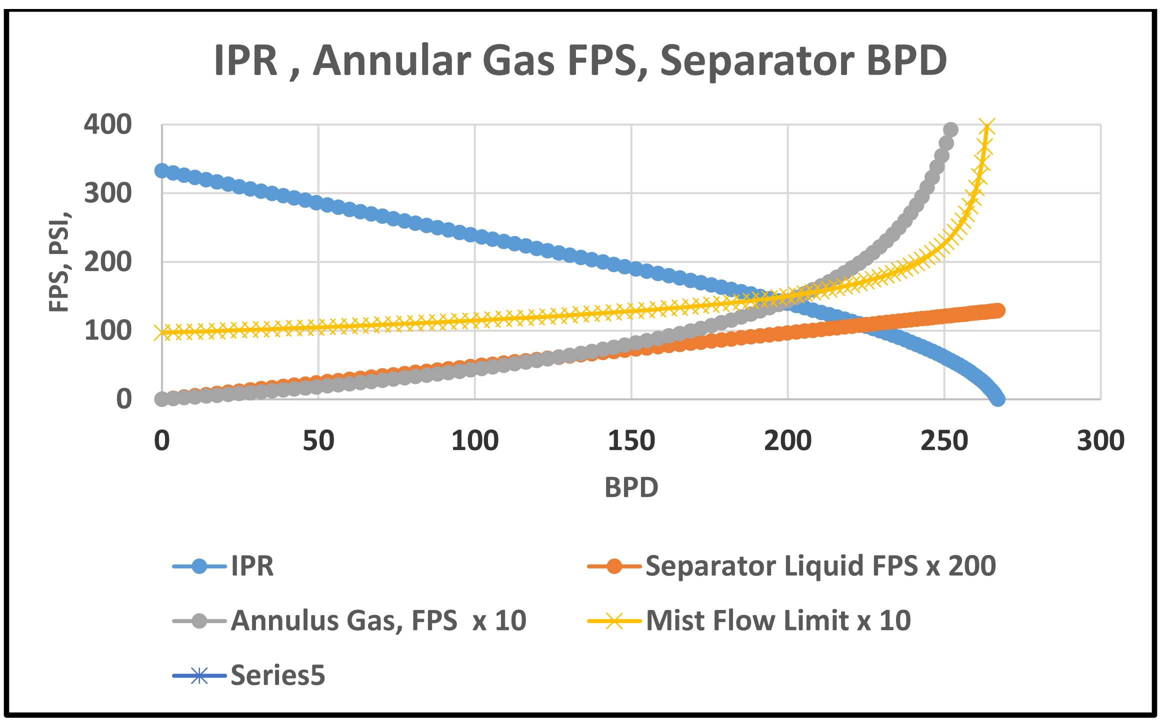


Figure 3: Results of the “medium gas” Case

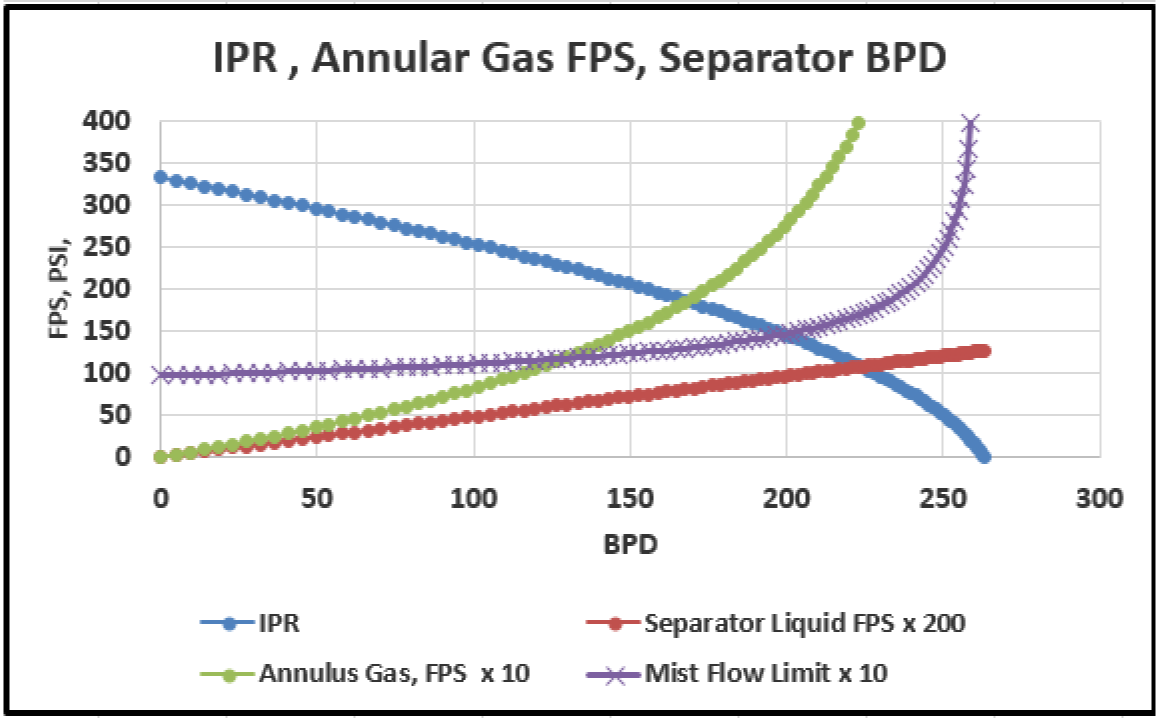


Figure 4.a: Results of the “High Gas Case”, Oil 90%

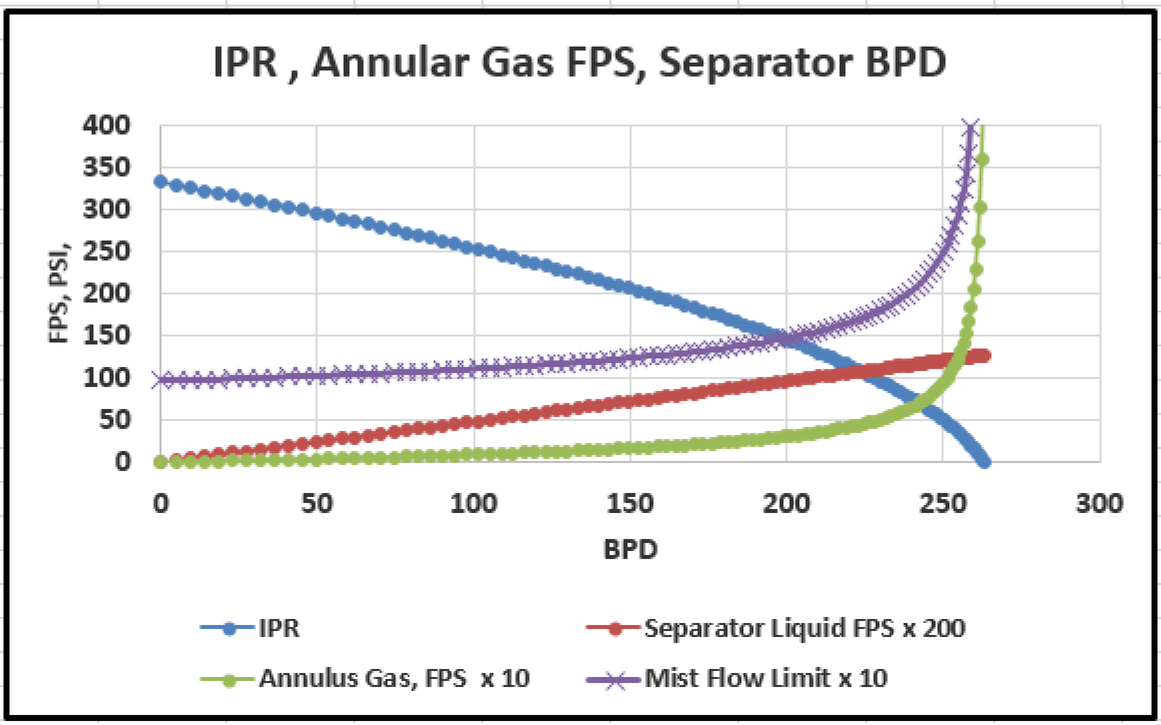


Figure 4.b: Results of the “High Gas Case”, Oil 10%

b

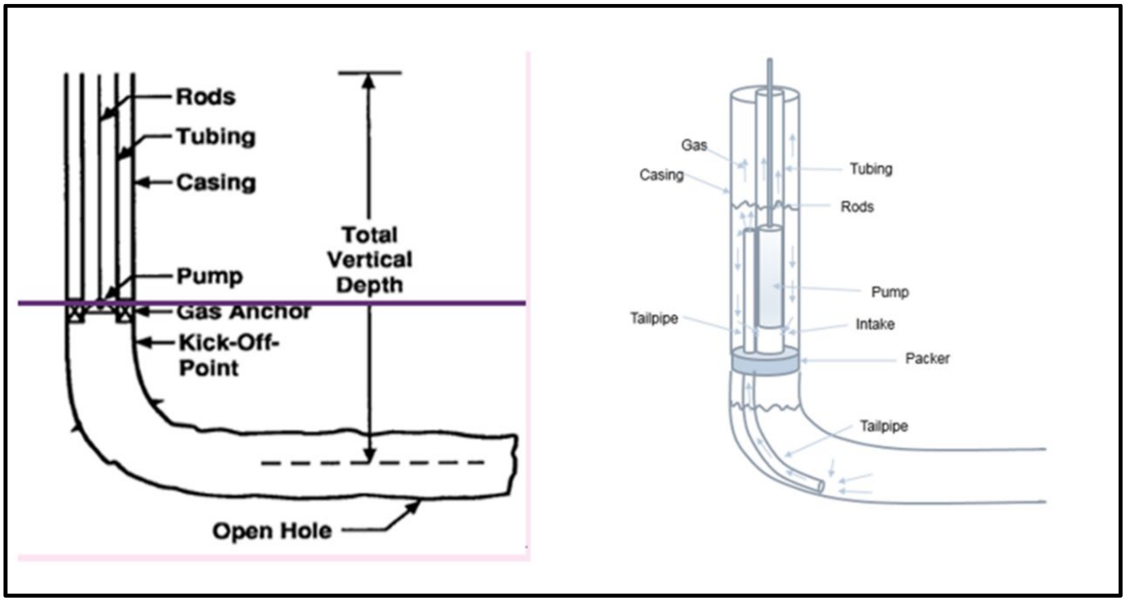
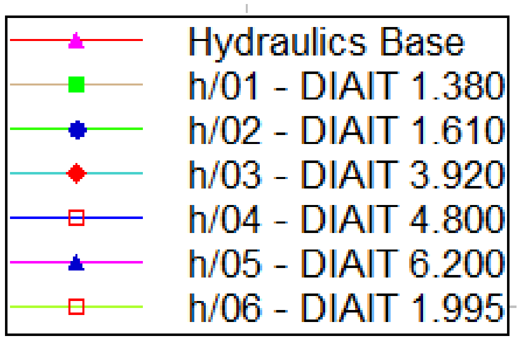


Figure 5: A pump installation with no tailpipe shown on the left and a pump installation with a tailpipe shown on the right. Both cases show the pump landed in the "near vertical" portion of the well.



Tubings Examined

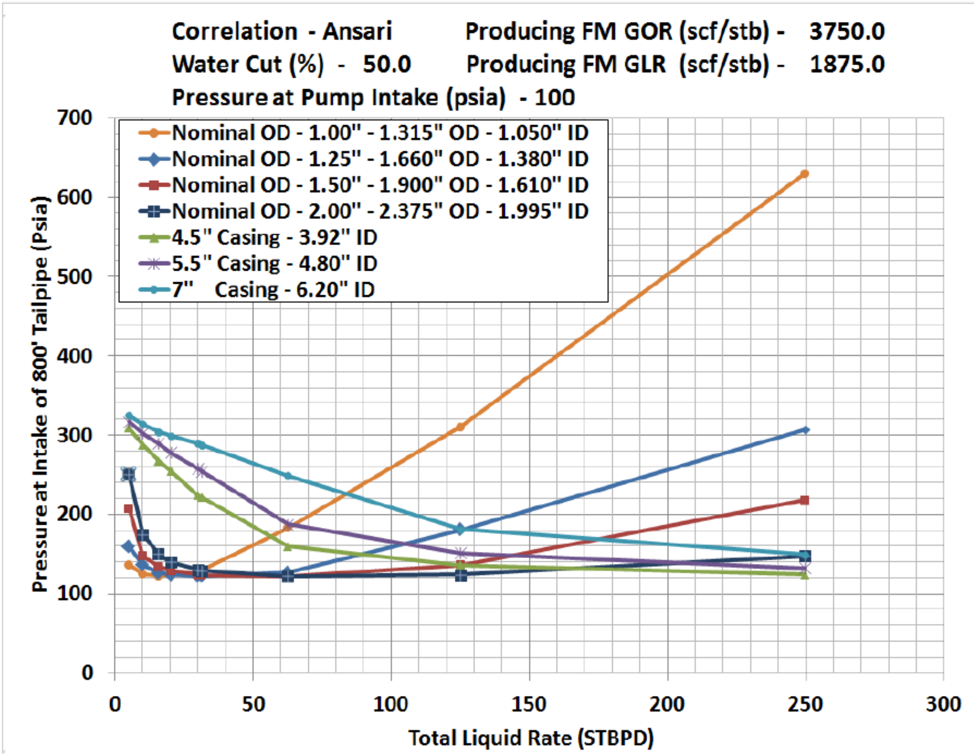


Figure 6 Diptube Nodal Performance

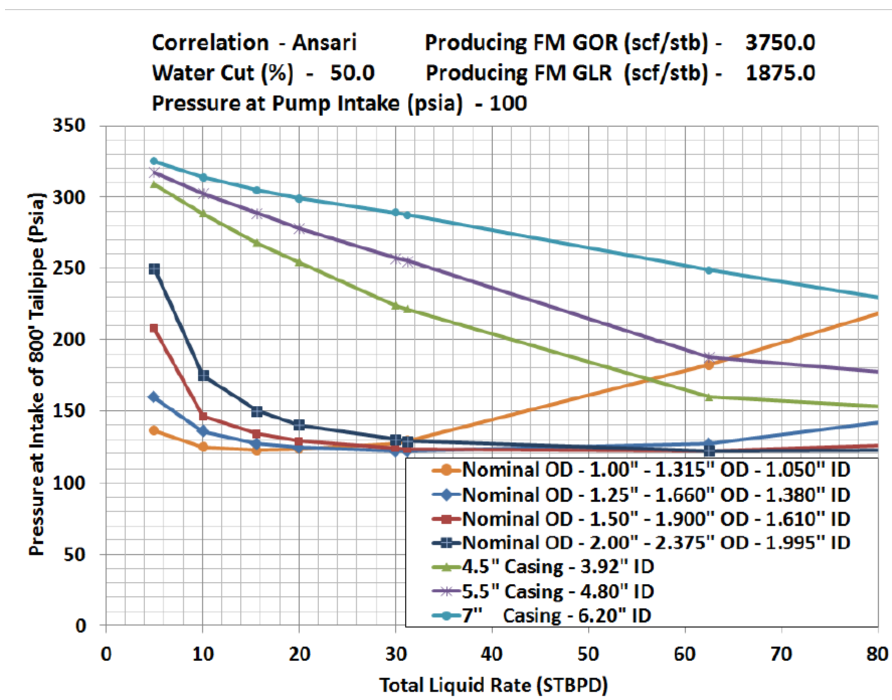


Figure 7: Nodal performance of the Dip Tubes at lower rates

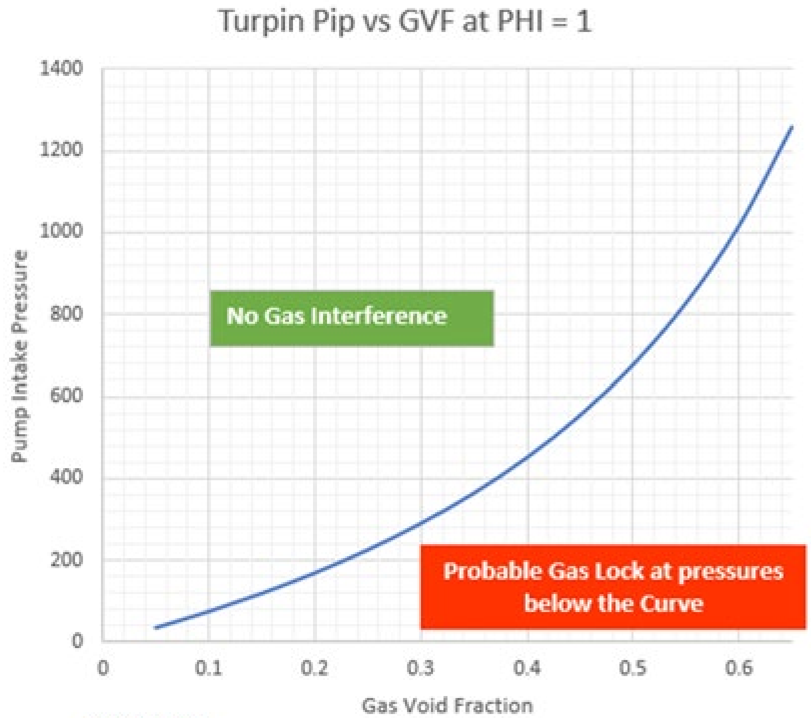


Figure 8

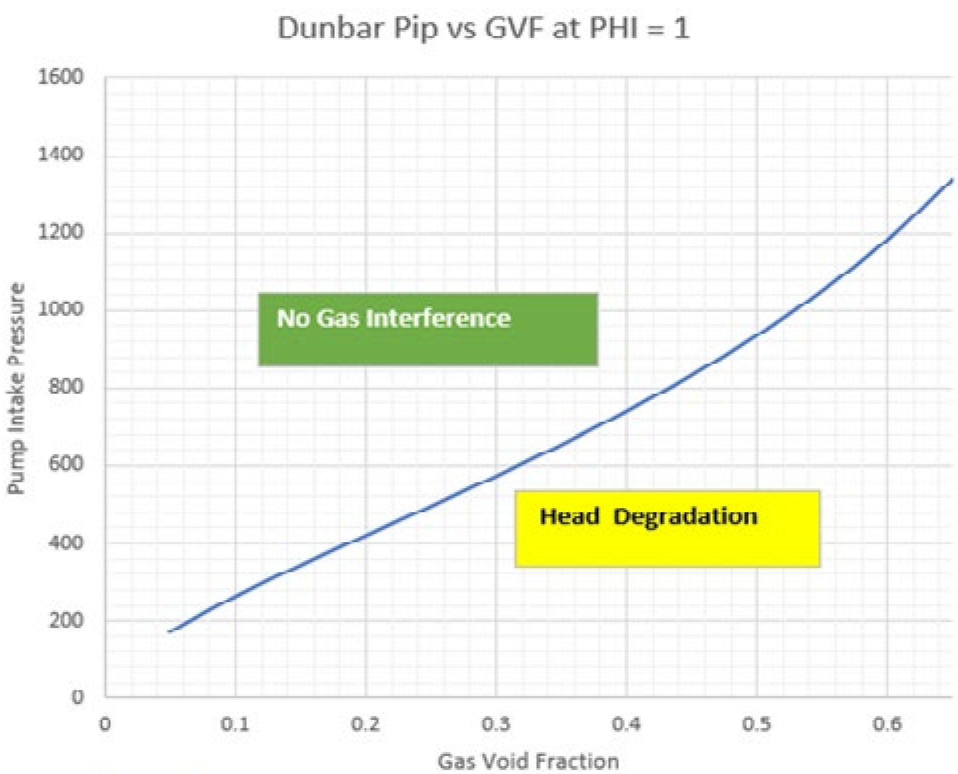


Figure 9

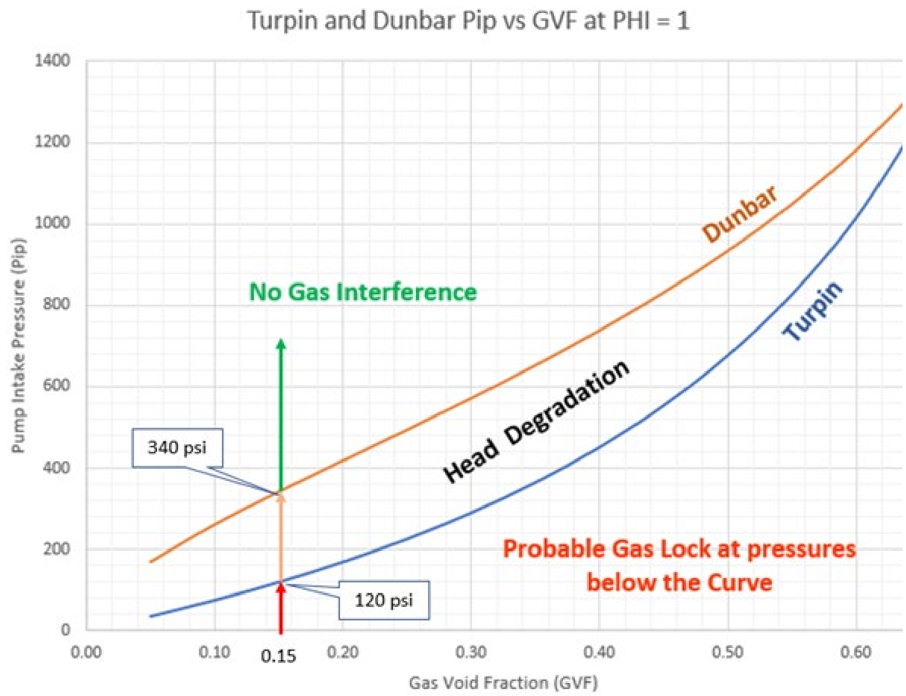


Figure 10

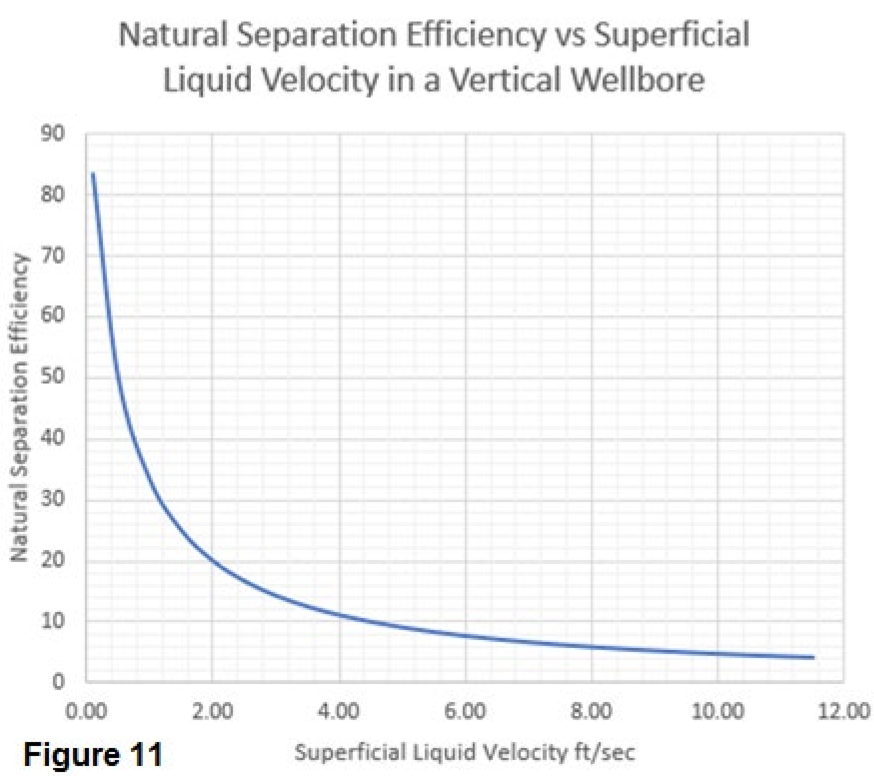


Figure 11

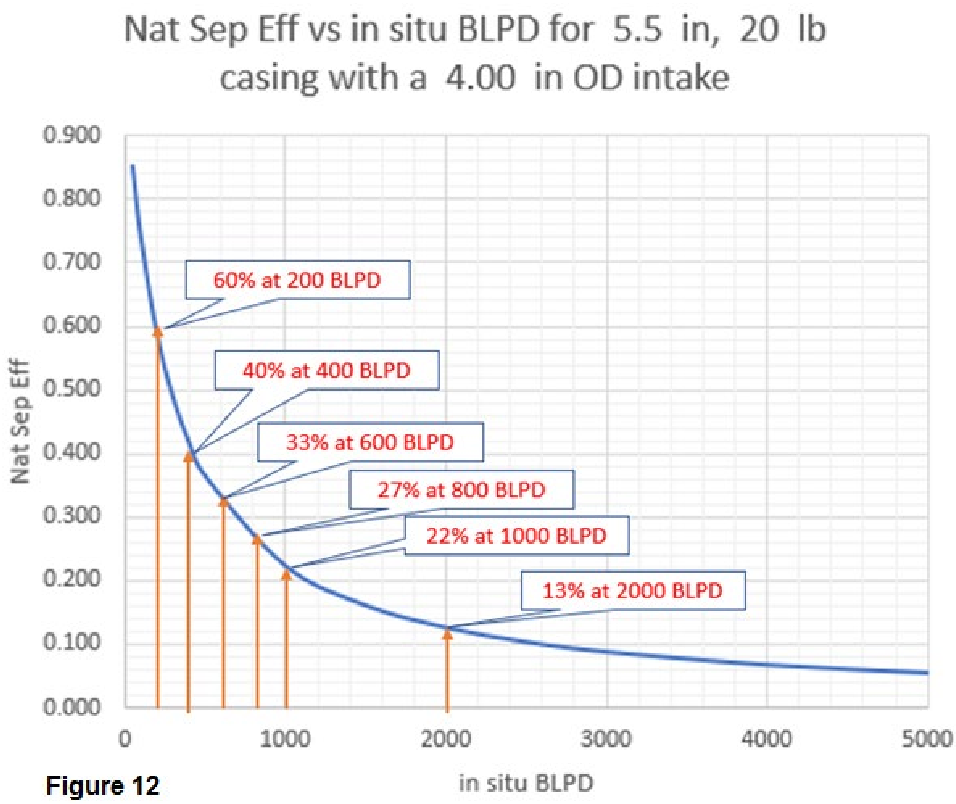
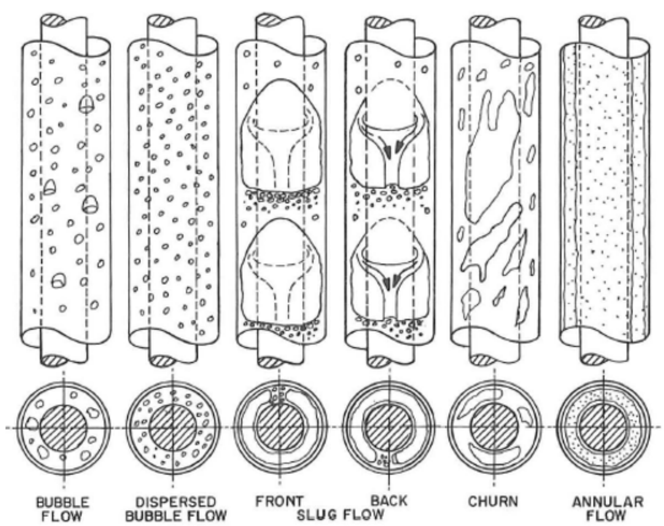
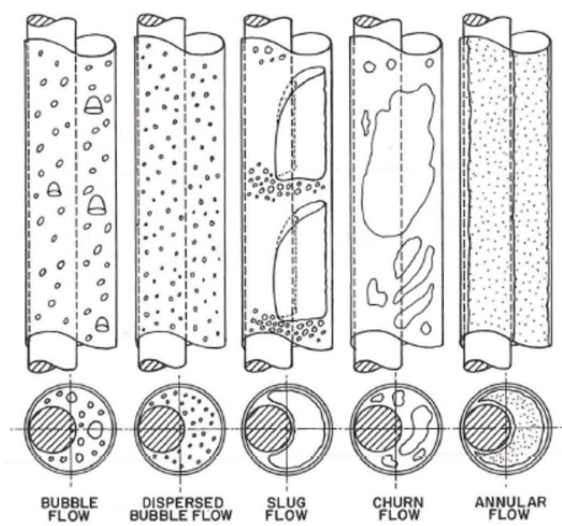


Figure 12



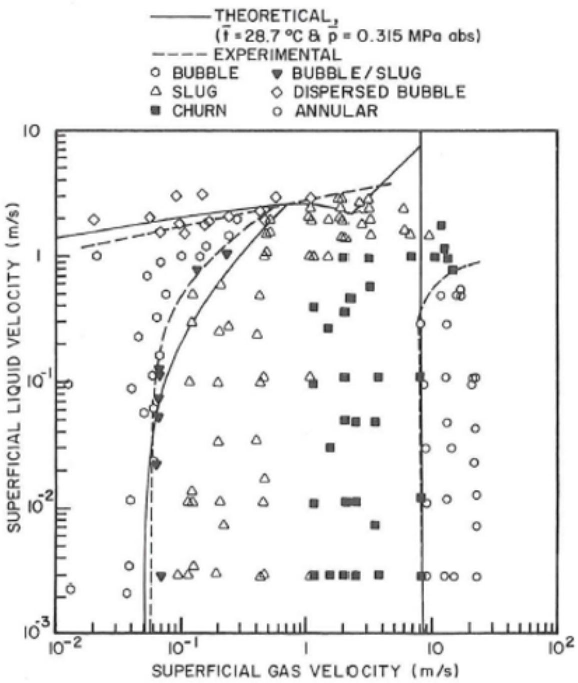
Flow patterns in upward vertical flow through a concentric annulus [6]

Figure 13A-1



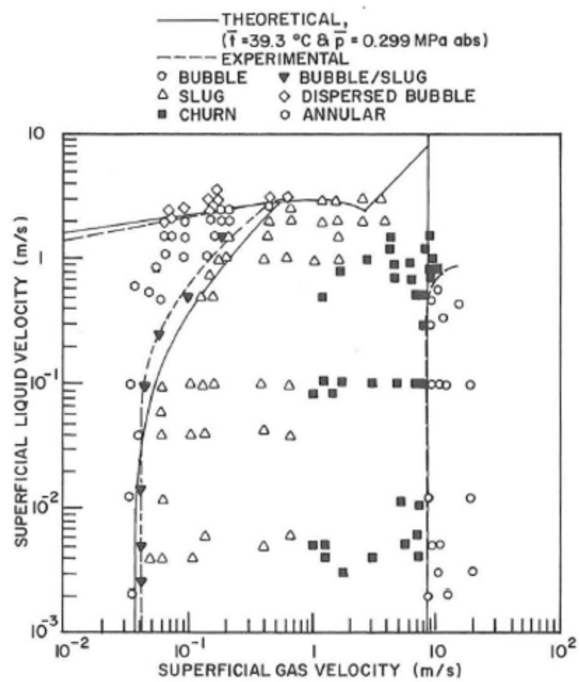
Flow patterns in upward vertical flow through a fully eccentric annulus [6]

Figure 13A-2



Flow pattern map for air - water-concentric annulus[6]

Figure 13B-1



Flow pattern map for air - water-fully eccentric annulus[6]

Figure 13B-2

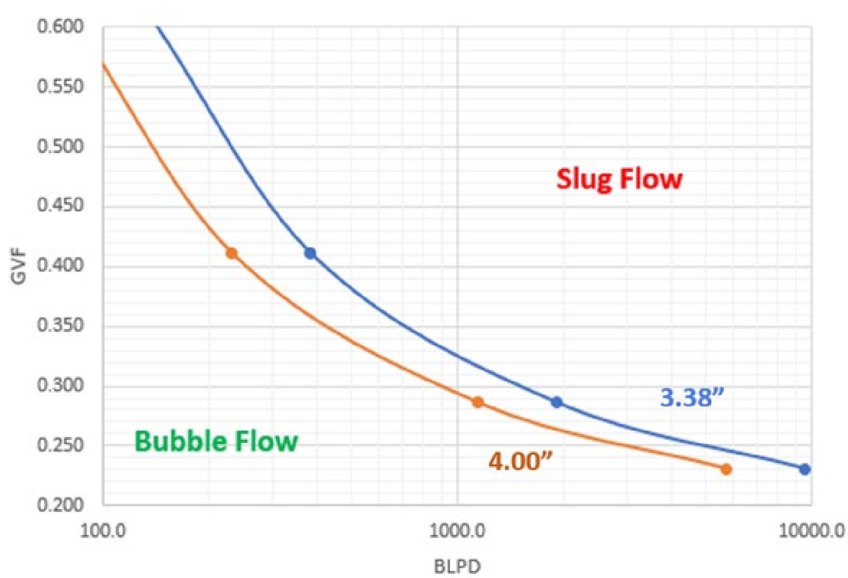
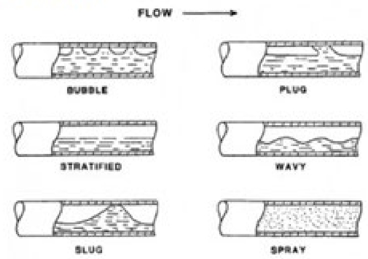


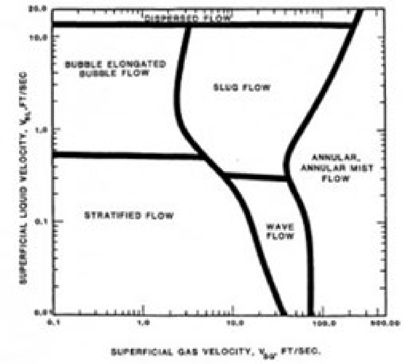
Figure 14: GVF vs BLPD for 3.38" and 4.00" intakes in 5.5", 20# Casing

Figure 15A:



TWO-PHASE PATTERNS IN HORIZONTAL FLOW

Figure 15B:



FLOW REGIME FOR HORIZONTAL PIPES

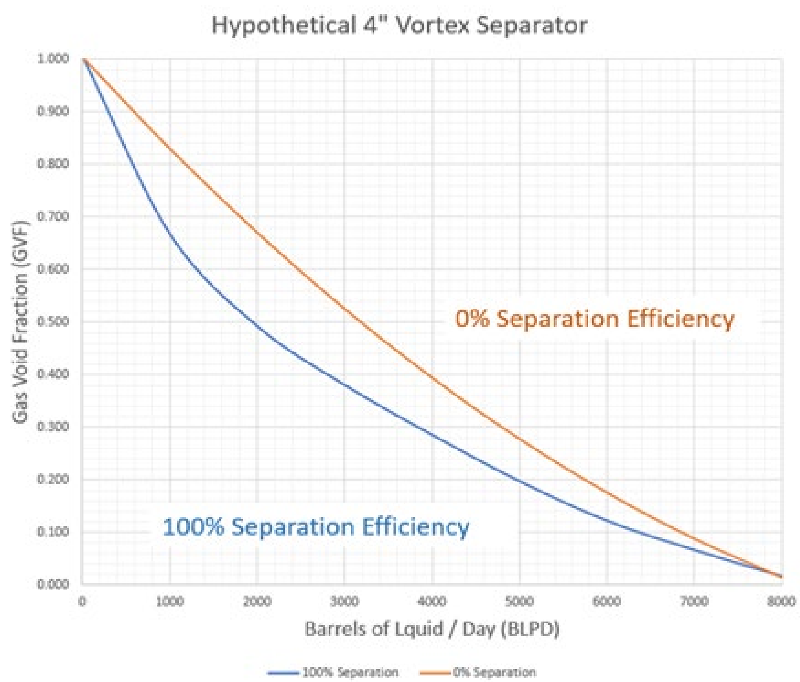


Figure 16: Example, after Dorzdov[10] data, adjusted for maximum Flow

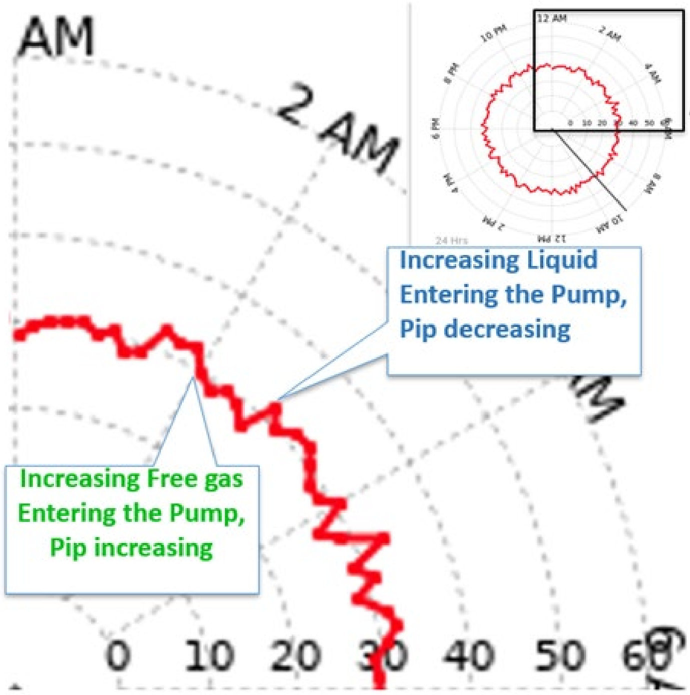


Figure 17:

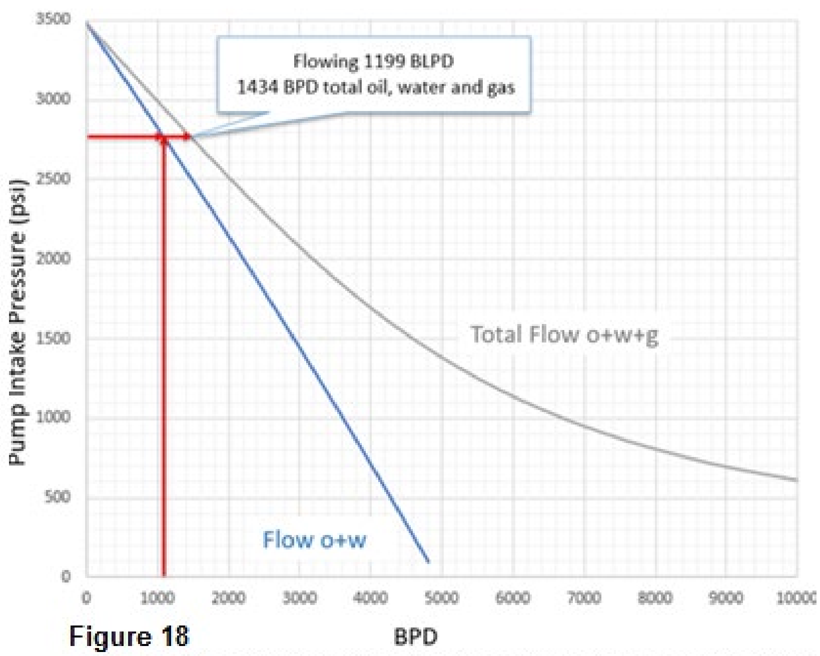


Figure 18
In-Situ Liquid and Liquid + Gas Flow Rates in the Annulus of the Pump Intake OD and Casing ID for a 4.00" Pump Intake and 5.5", 20# Casing

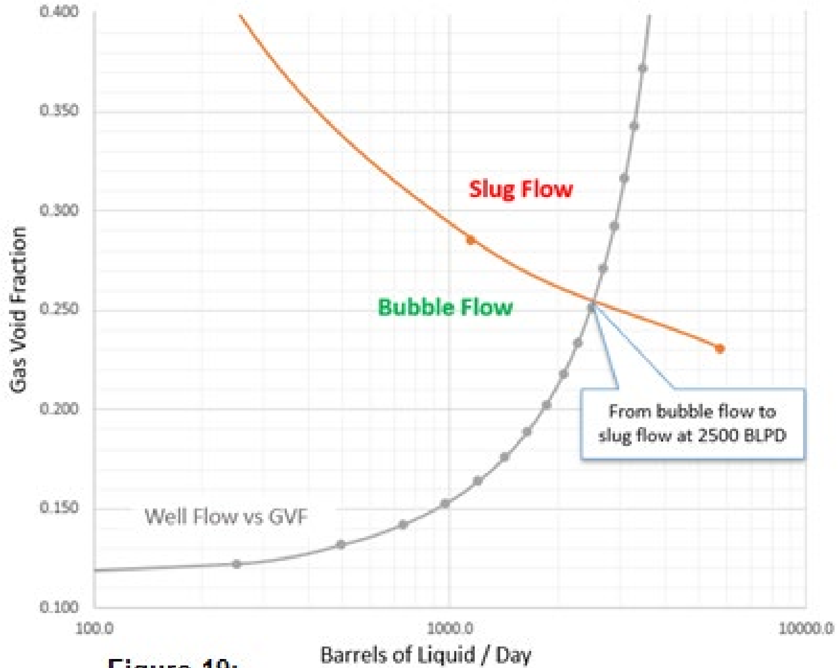


Figure 19:
BLPD vs GVF for the Bubble Flow – Slug Flow Boundary
With the Example 1 BLPD vs GVF

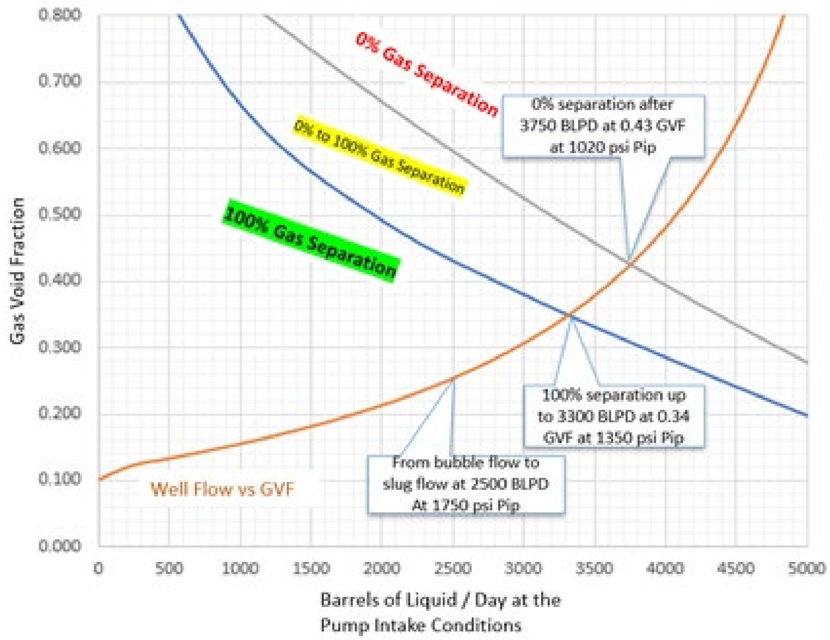


Figure 20 Well BLPD vs GVF with Hypothetical 4" Vortex Separator Curves for Example 1

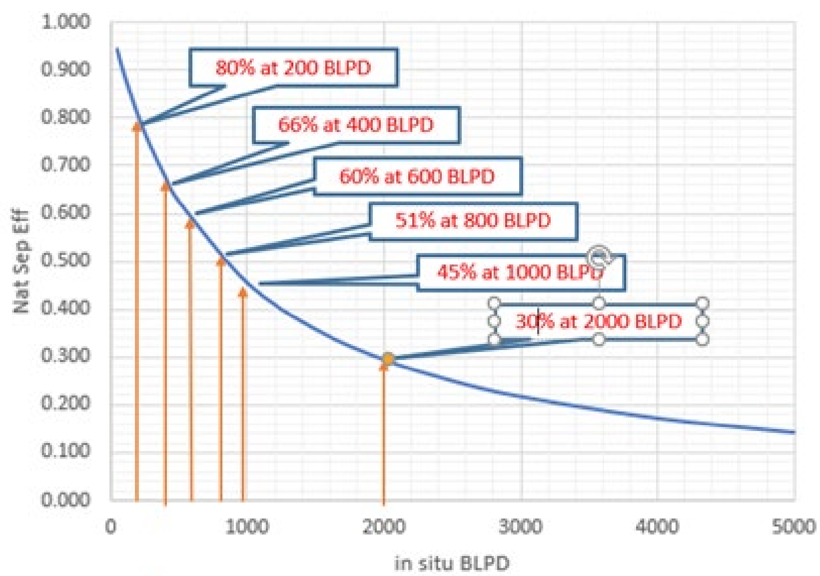


Figure **21:**

Nat Sep Eff vs in situ BLPD for 7 in, 35 lb casing with a 4.00 in OD intake

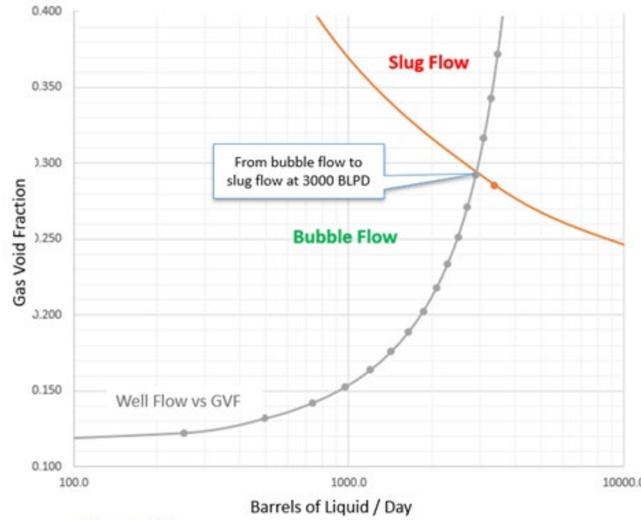


Figure 22:
BLPD vs GVF for the Bubble Flow – Slug Flow Boundary
With the Example 2 BLPD vs GVF

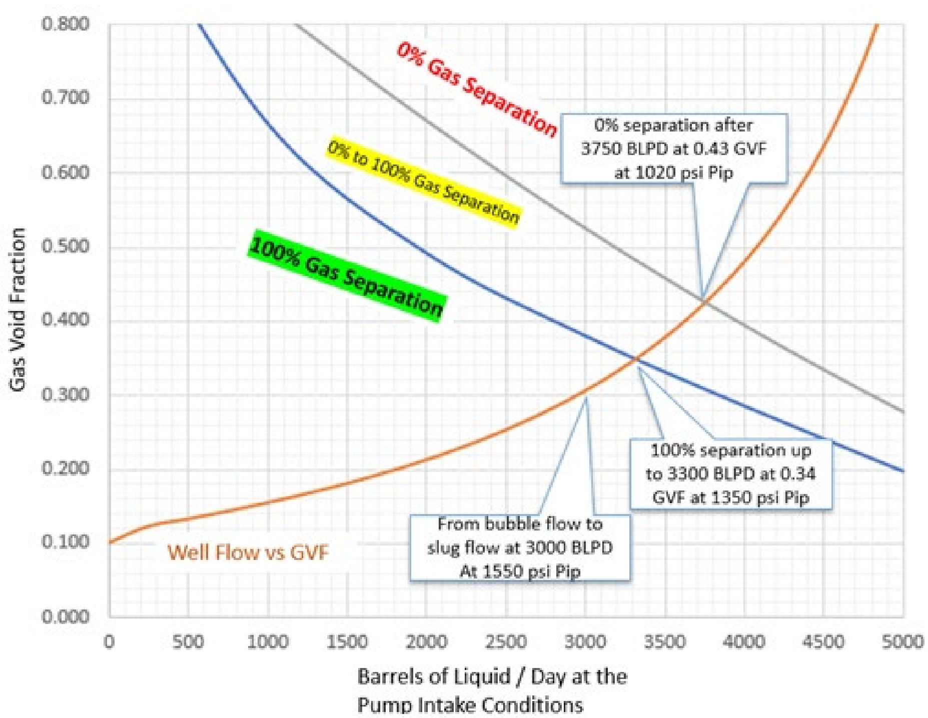


Figure 23: Well BLPD vs GVF with Hypothetical 4"
Vortex Separator Curves for Example 2

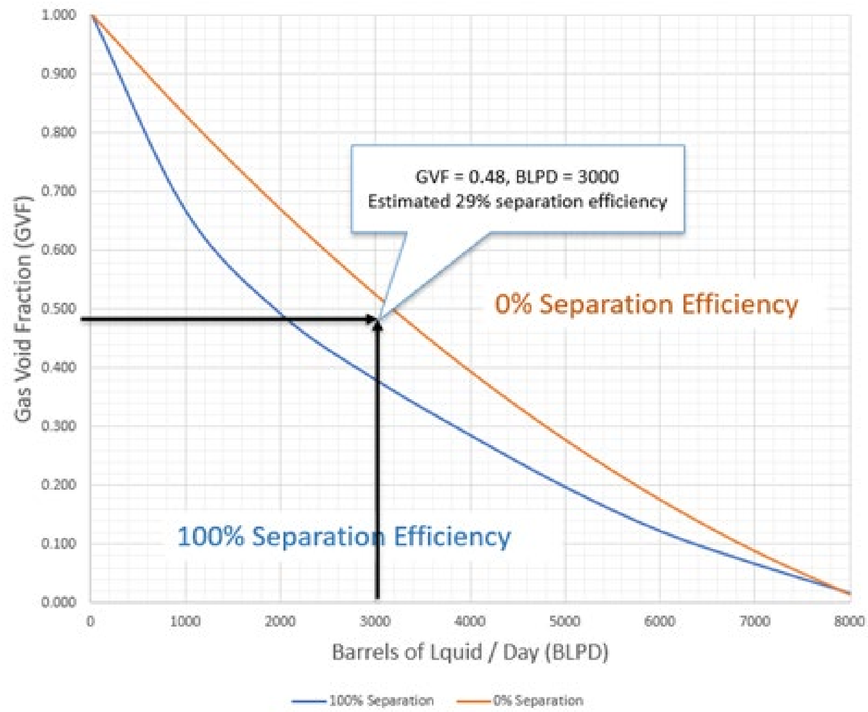


Figure **24**: First or Lower Tandem Hypothetical 4" Vortex Separator

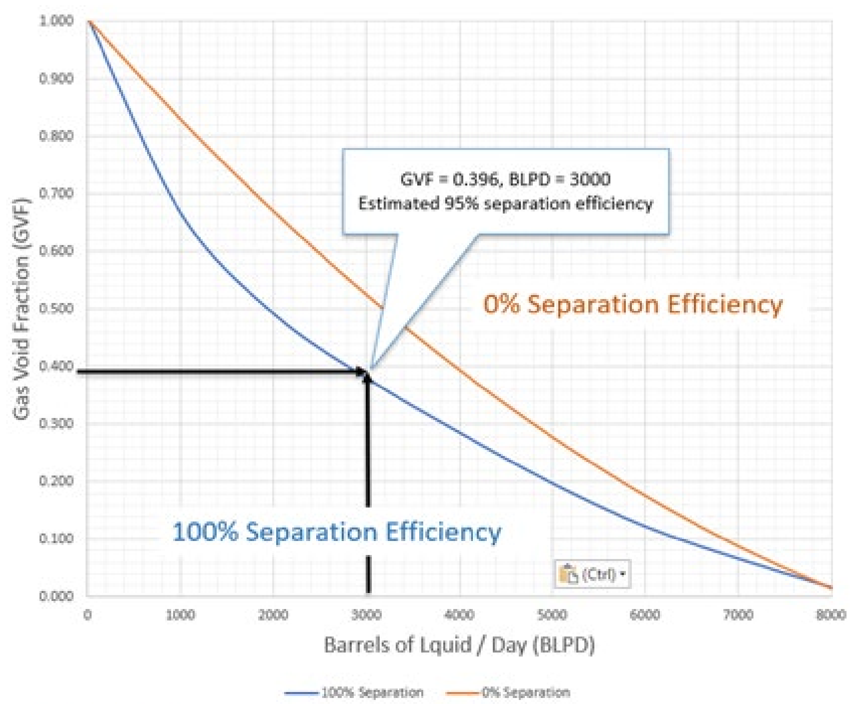


Figure 25: Second or Upper Tandem Hypothetical 4" Vortex Separator