How a Well Flows

- Natural flow and tubing selection
- Well heading and unloading
- Artificial lift selection

- In many cases, we produce wells in spite of ourselves. Production optimization involves minimizing the pressure drops in the flowing system from the outer edge of the reservoir to the pipeline or storage tank.

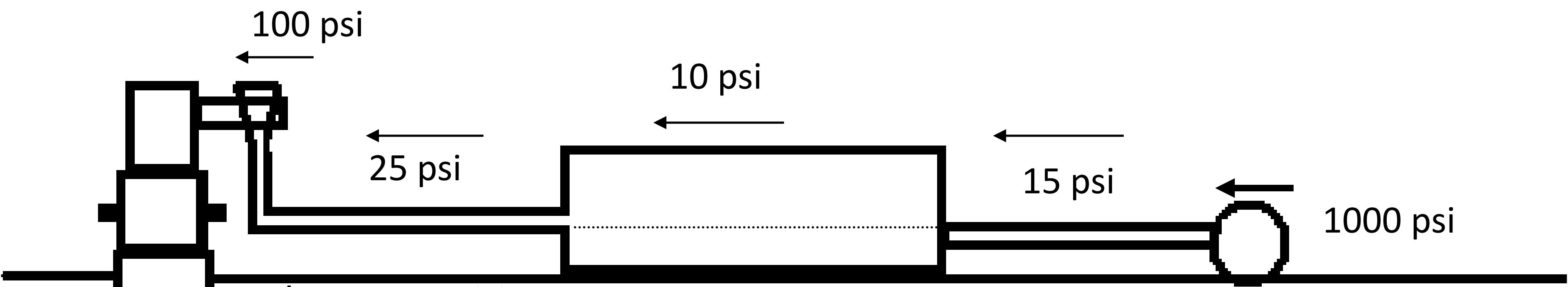
The flow equation

- **Inflow Variables**
  - Height of reservoir (contact height)
  - Radius of the reservoir
  - Matrix, natural fracture and hydraulic fracture coverage and permeability/flow capacity – and how it changes over time.
  - Differential pressure (the main driving force to move fluids)
  - Viscosity of the hydrocarbon
- **Outflow Variables**
  - Diameter(s) and length of flow path (the casing below the packer and the tubing)
  - Velocities in each section (above critical to lift liquids)
  - Hydrostatic head (the flowing and the static heads as back pressures)
  - Backpressures (fracture, perf and tubing friction, choke, surface line friction, surface line elevation, separator and sales line pressure, etc.)

The factors controlling flow:

- To increase flow:
  - Increase pressure differential between reservoir and sales line.
  - Look at the major pressure drops and eliminate them
  - Keep the velocities above the critical velocities in each section
  - Balance the critical lift needs with the lowest friction possible.

Differential pressure, ΔP, is actually a pressure balance



Column Densities:

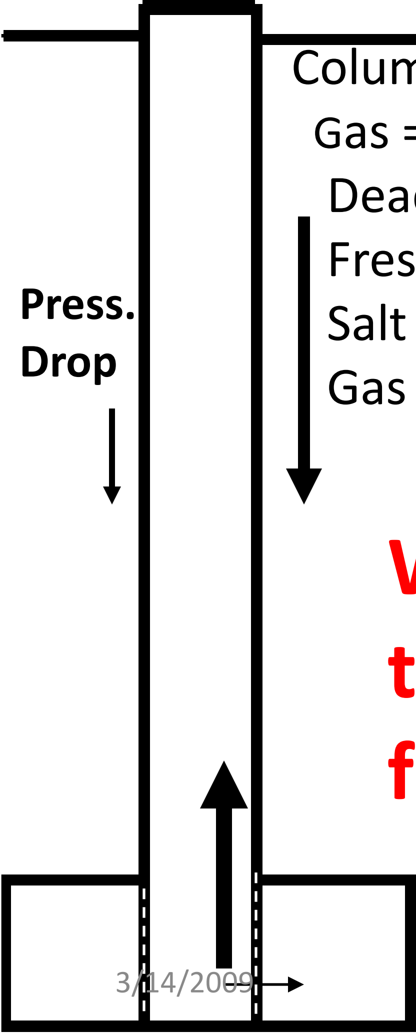
Gas = 1.9 lb/gal = 0.1 psi/ft = 1900 psi in a 10,000 ft TVD well

Dead oil = 7 lb/gal = 0.364 psi/ft = 3640 psi in a 10,000 ft TVD well

Fresh water = 8.33 lb/gal = 0.433 psi/ft = 4330 psi in 10,000 ft TVD well

Salt water = 10 lb/gal = 0.52 psi/ft = 5200 psi in a 10,000 ft TVD well

Gas cut flowing oil= 5 lb/gal = 0.26 psi/ft = 2600 psi in 10,000 ft TVD well



Where does the ΔP come from?

4600 psi reservoir pressure (initial)
-2600 psi flowing gradient for oil
- 150 psi press drop from friction
- 100 psi through the choke
- 25 psi through the flow line
- 10 psi through the separator
- 15 psi through downstream flow line
-1000 psi sales line entry pressure

ΔP = 700 psi drawdown pressure

Now, What can be done to improve the flow rate?

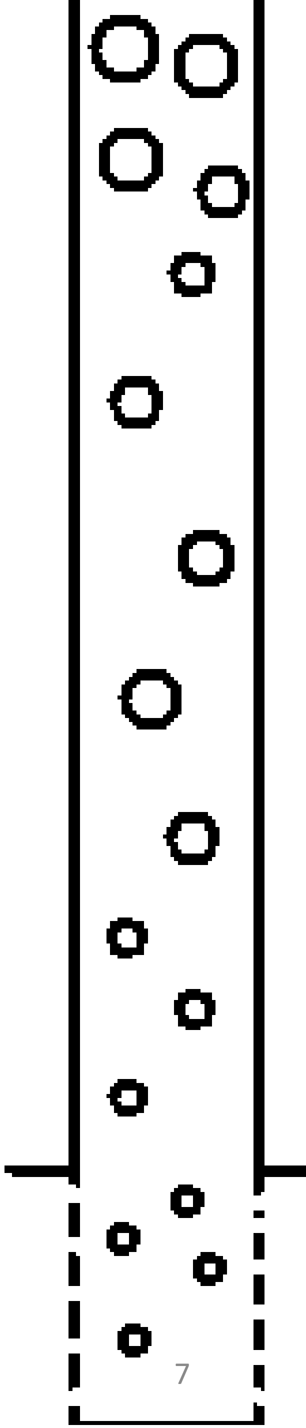
- What pressure drops or back pressures are the highest?
  - Gradient of the fluid at 2600 psi
  - Sales line back pressure at 1000 psi
  - Flowing pressure drop at 150 psi
  - Choke at 100 psi
- Which can be changed with the maximum economic impact? (Many involve well entry and expensive surface construction.)
- Which can be changed easiest, quickest and cheapest? (Some are as easy as a choke change or adding a compressor.)

What are the remedial actions?

- Gradient of the fluid: LIFT
- Sales line back pressure: Larger line?
- Flowing pressure drop: Larger tubing or lower friction pressure
- Choke: why is a choke needed? Is it needed here? Test it!

Expansion of gas occurs as the gas rises from the bottom of the well. The expanding gas can entrain and carry liquid with it if the flow rate reaches critical velocity (the velocity necessary to lift liquid).

Remember – the volume of the gas bubble (and indirectly the velocity of the upward flowing fluid) is controlled by the pressure around it. This pressure is provided by the formation pore pressure and controlled by the choke and other back pressure resistances.

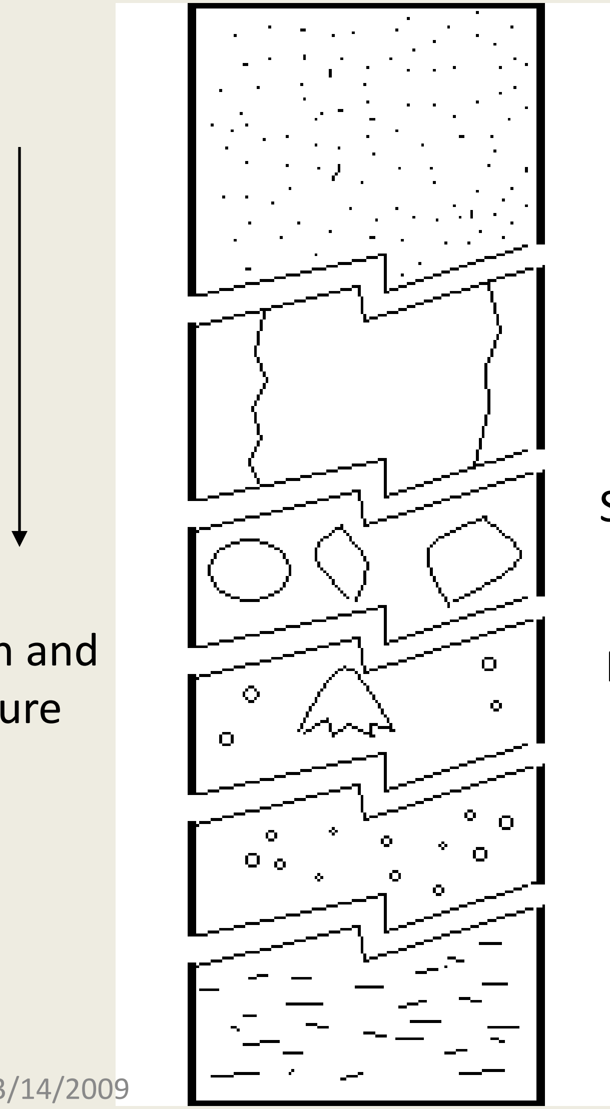


The difference in rise rate is linked to the diameter of the pipe.

Velocity of Bubbles Rising Through Water

Author	Tube Radius in.	Water Viscosity cp	Liquid Velocity ft/sec	Bubble Rise Velocity ft/sec
Davies and Taylor	0.24	1	0	0.325
	0.43	1	0	0.49
	1.56	1	0	0.975
Laird and Chisholm	1	1		0.825
Griffith and Wallis	0.25	1.3		0.35
			0.39 (up)	0.43
			0.81 (up)	0.5
	0.38	1.3	0	0.48
			0.35 (up)	0.64
			0.92 (up)	0.75
			0.20 (up)	0.4
	0.5	1.3	0	0.58
		0.6	0	0.58
		1.3	0.50 (up)	0.71
			0.99 (up)	0.81
			0.14 (down)	0.55
Ward	0.17	1	0	0.19
	2.78	1	0	1.41
	5	1	0	1.91
Johnson and White	3.9	1	0	1.81

The type of flow pattern changes with the expansion of the gas. One or more of the flow patterns may be present in different parts of the well. The flow patterns may explain differences in lift, corrosion and unloading.



Mist Flow – external phase is gas with a small amount of liquid

Channel or annular flow

Slug or churn flow

Piston flow

Bubble flow

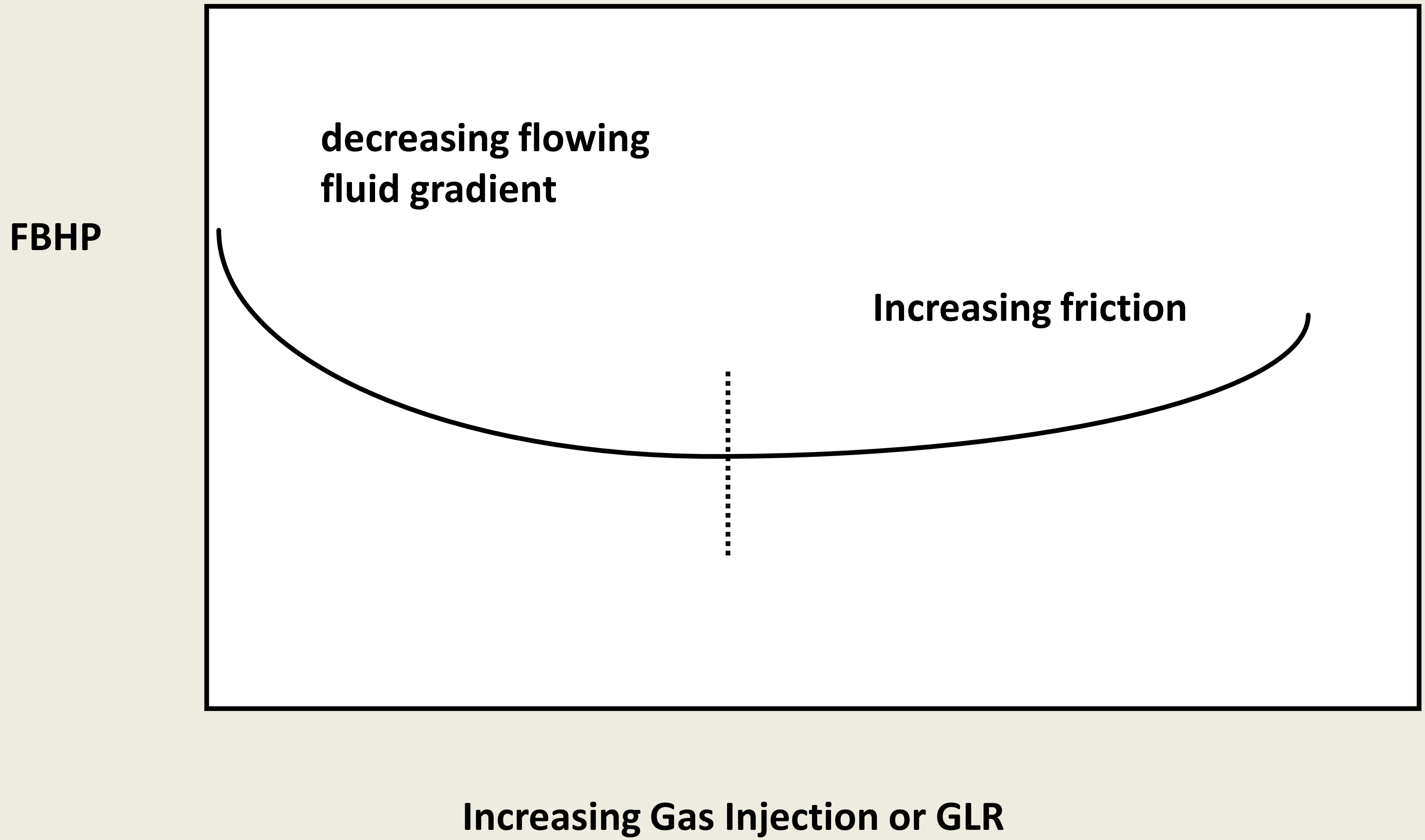
Single phase liquid flow

Depth and Pressure

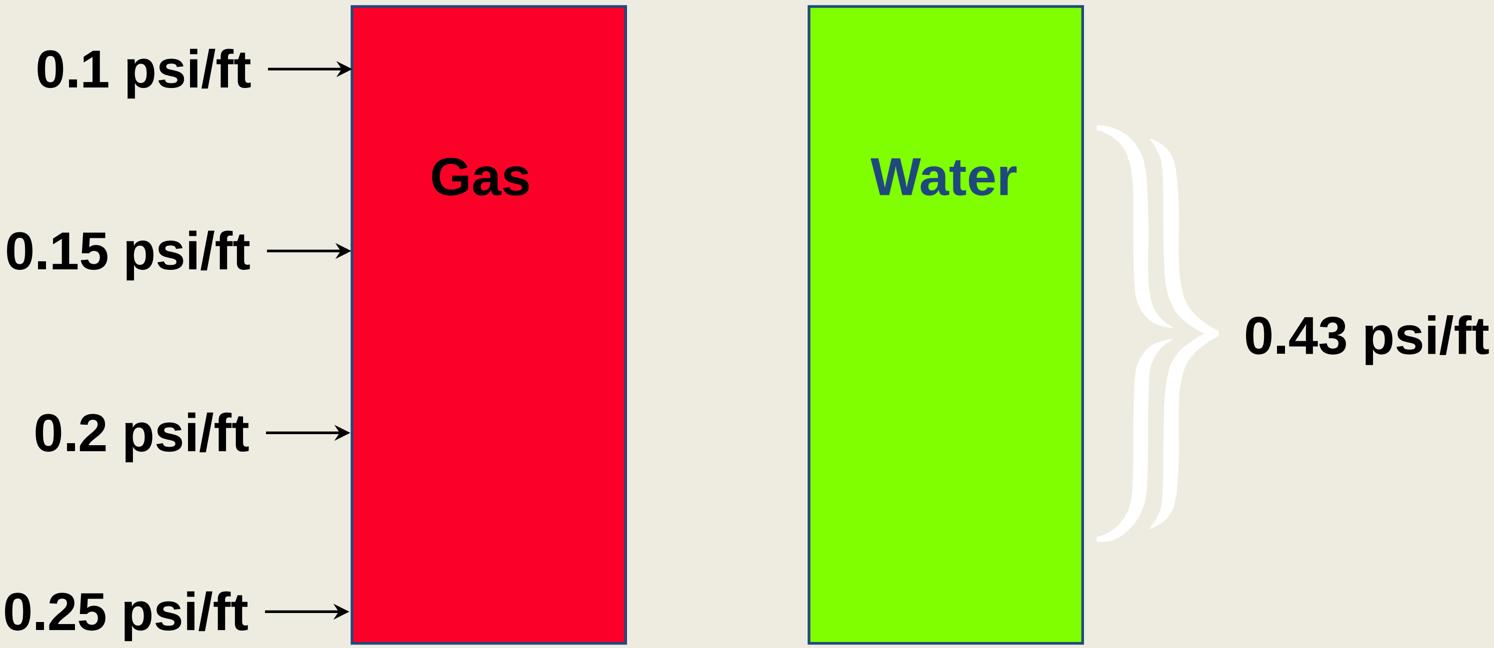
Density of the Flowing Column

- Decreasing the density of the column of the flowing fluid is one of the best things that can be done to increase draw down and flow rate.

Effect of increasing GLR on Flowing Bottom Hole Pressure (FBHP) – As gas is added, the FBHP decreases due to gas cut liquid. When too much gas is added, the friction from the flowing volume increases.



Density of a Column of Fluid



The compressibility of the gas, and the energy stored by that compression, is a key to the flowing energy of the system.

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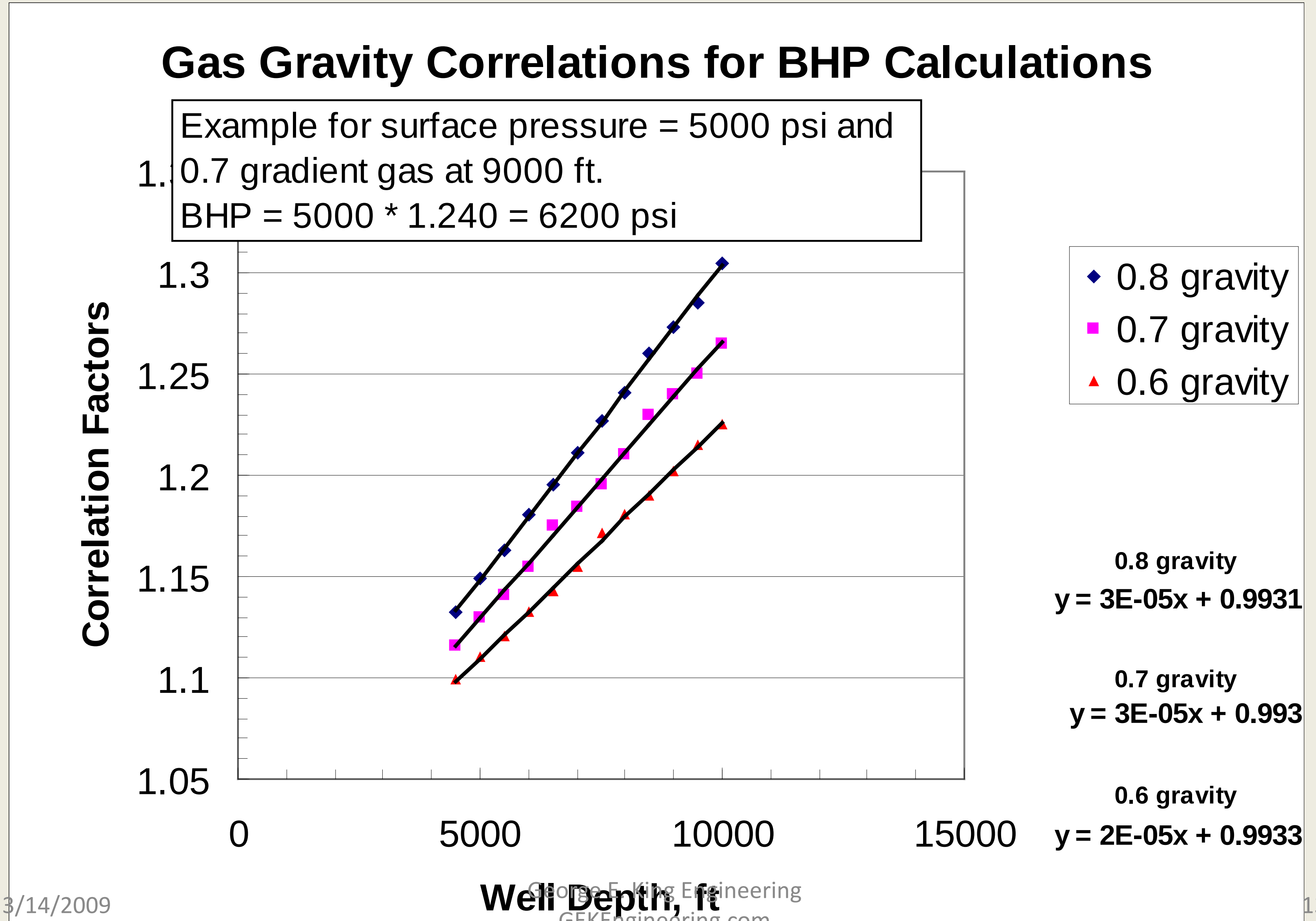
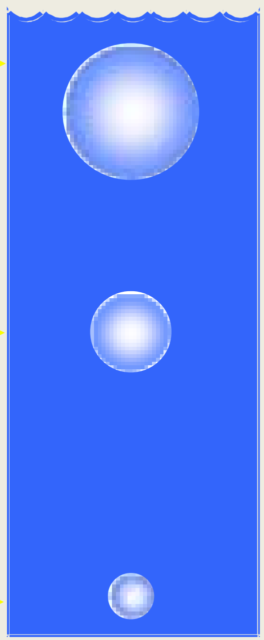
Calculating More Accurate BHP with Gas Head



Size of a Bubble in a Water Column



292 cm^3

2 cm^3

1 cm^3

surface		14.7 psi (1 bar)
5000 ft (1524m)		2150 psi (146 bar)
10000 ft (3049m)		4300 psi (292 bar)

What will the expansion of the bubbles produce at surface? Energy and friction.

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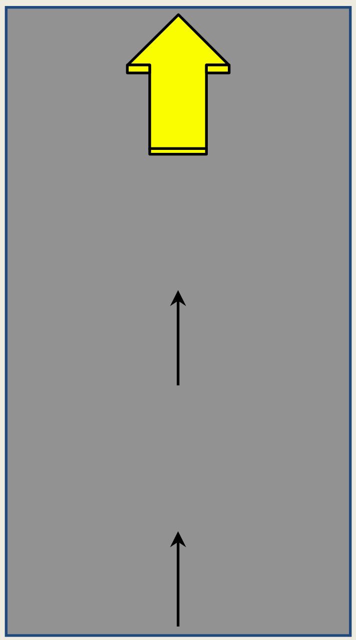
Velocities Along a Column

~300 fps(?)



surface — 14.7 psi (1 bar)

60 fps

5000 ft (1524m) — 2150 psi (146 bar)

30 fps

10000 ft (3049m) — 4300 psi (292 bar)

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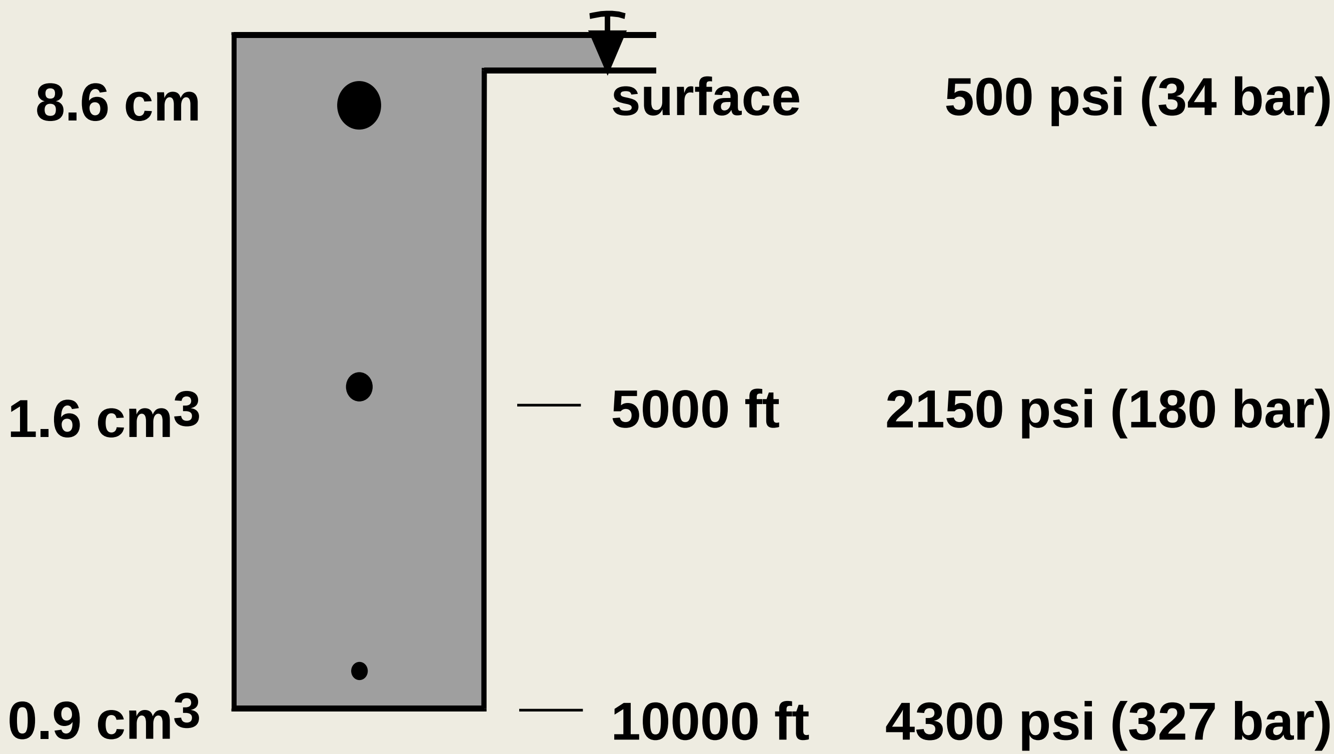
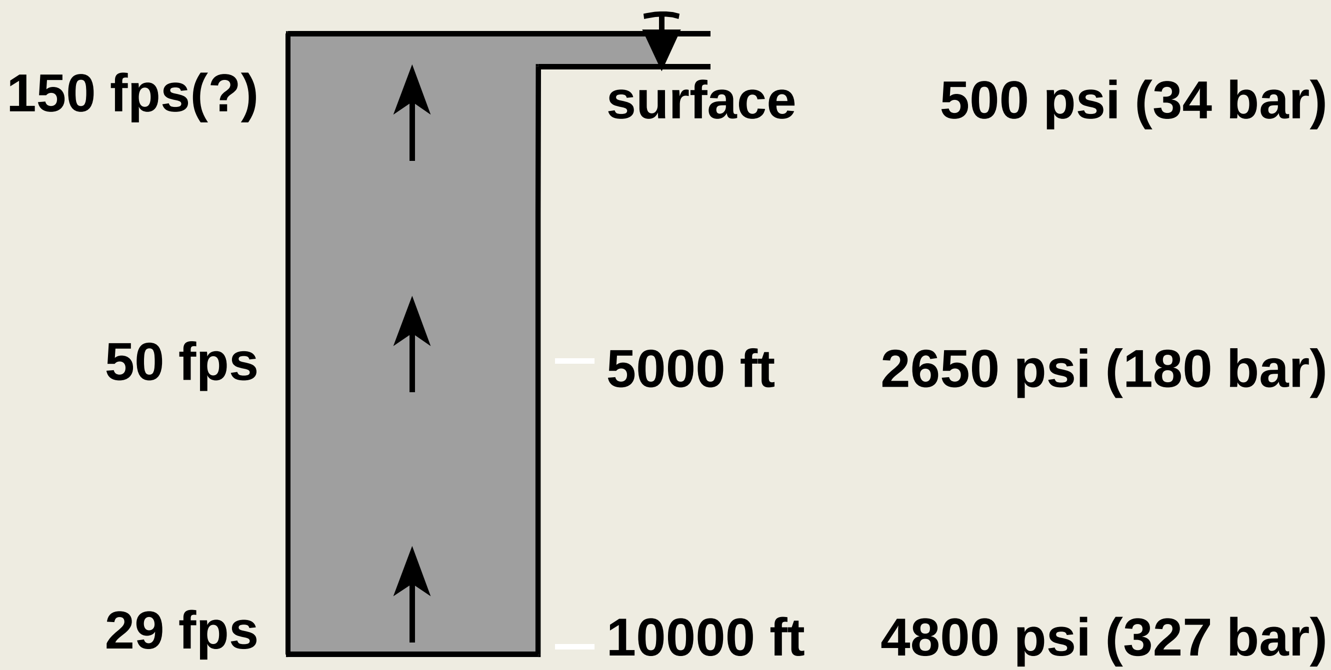
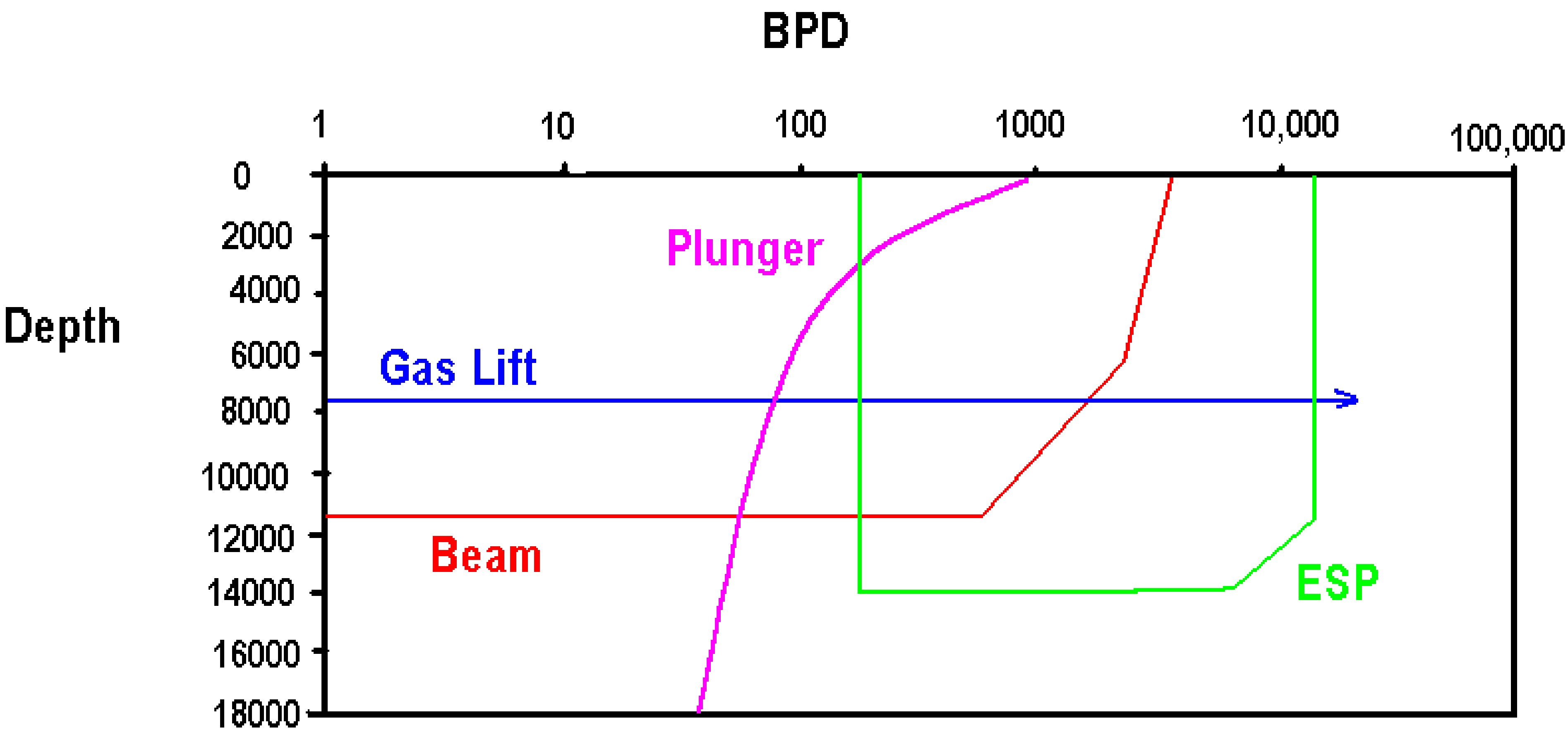
Using a Choke
(500 psi Back Pressure)

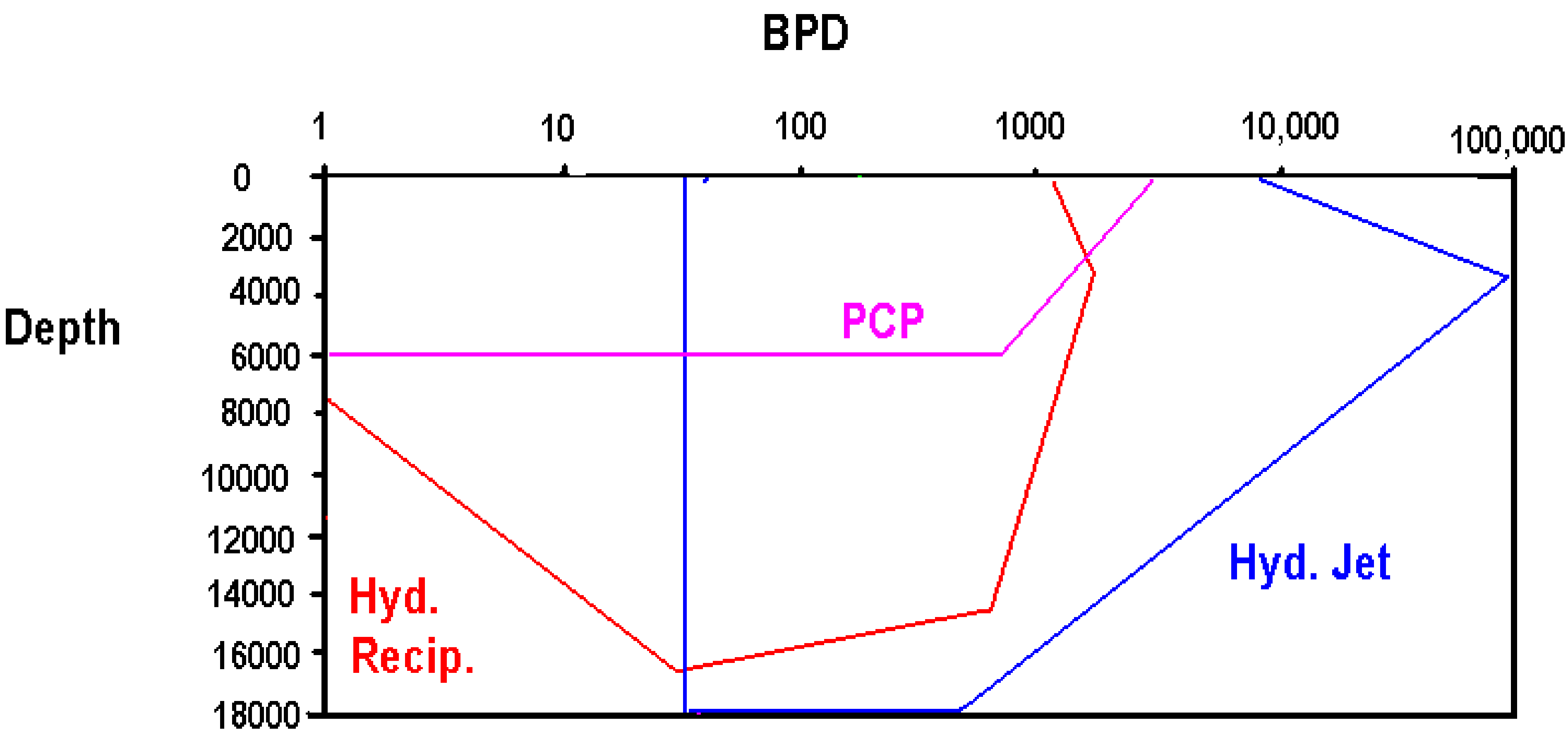


Velocities After Choke in Place



Lift systems all have advantages and disadvantages. Each system requires power and how that power is applied often limits the use.





Pennwell AL Charts, 1986

Lift Methods and Unloading Options

- Most mechanical methods are build for oil wells – that's grossly over designed for gas wells and much too expensive.
- A "dry" gas well may produce on 4 to 16 ounces of water or condensate per minute (100 to 500 cc/min). This is a much different unloading problem.

Lift and Unloading Options

Method	Description	Pros	Cons
Natural Flow	Flow of liquids up the tubing propelled by expanding gas bubbles.	Cheapest and most steady state flow	May not be optimum flow. Higher BHFP than with lift.
Continuous Gas Lift	Adding gas to the produced fluid to assist upward flow of liquids. 18% efficient.	Cheap. Most widely used lift offshore.	Still has high BHFP. Req. optimization.
ESP or HSP	Electric submersible motor driven pump. 38% efficient. Or hydraulic driven pump (req. power fluid path).	Can move v. large volumes of liquids.	Costly. Short life. Probs. w/ gas, solids, and heat.

Lift and Unloading Options

Method	Description	Pros	Cons
Hydraulic pump	Hydraulic power fluid driven pump. 40% efficient.	Works deeper than beam lift. Less profile.	Req. power fluid string and larger wellbore.
Beam Lift	Walking beam and rod string operating a downhole pump. Efficiency just over 50%.	V. Common unit, well understood,	Must separate gas, limited on depth and pump rate.
Specialty pumps	Diaphram or other style of pump.	Varies with techniques.	New - sharp learning curve.

Lift and Unloading Options

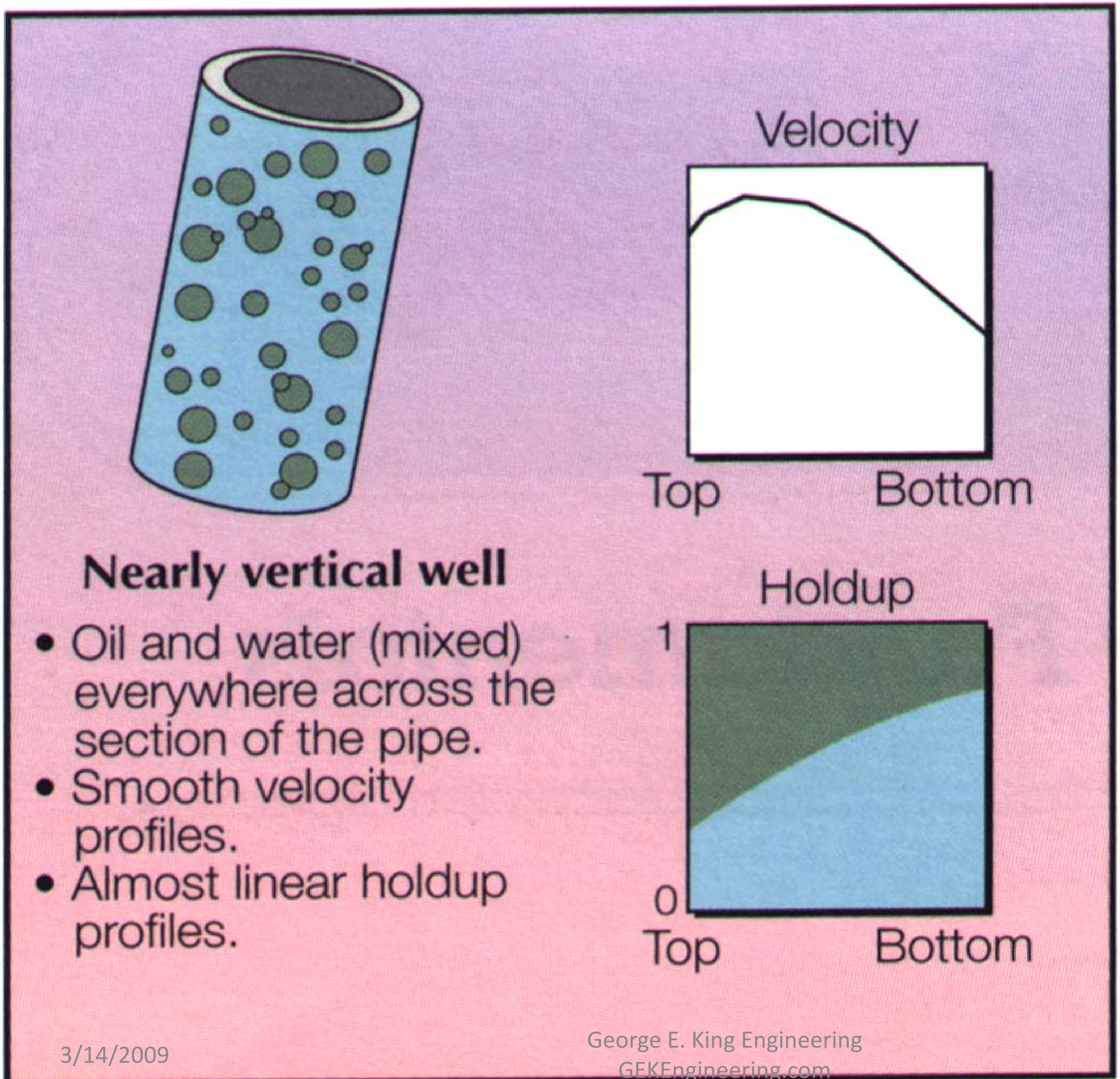
Method	Description	Pros	Cons
Intermittent Gas Lift	**Uses gas injected usually at one point to kick well off or unload the well followed by natural flow. 12% efficient.**	**Cheap and doesn't use the gas volume of continuous GL.**	**Does little to reduce FBHP past initial kickoff.**
Jet pump	**Uses a power fluid through a jet to lift all fluids**	**Can lift any GOR fluid.**	**Req. power fluid string. Probs with solids.**
PCP	**Progressive cavity pump.**	**Can tolerate v. large volumes of solids and ultra high visc. fluids.**	**Low rate, costly, high power requirements.**
Plunger	**A free traveling plunger pushed by gas below to mover a quantity of liquids above the plunger.**	**Cheap, works on low pressure wells, control by simple methods**	**Limited volume of water moved, cycles backpressure.**

Lift and Unloading Options

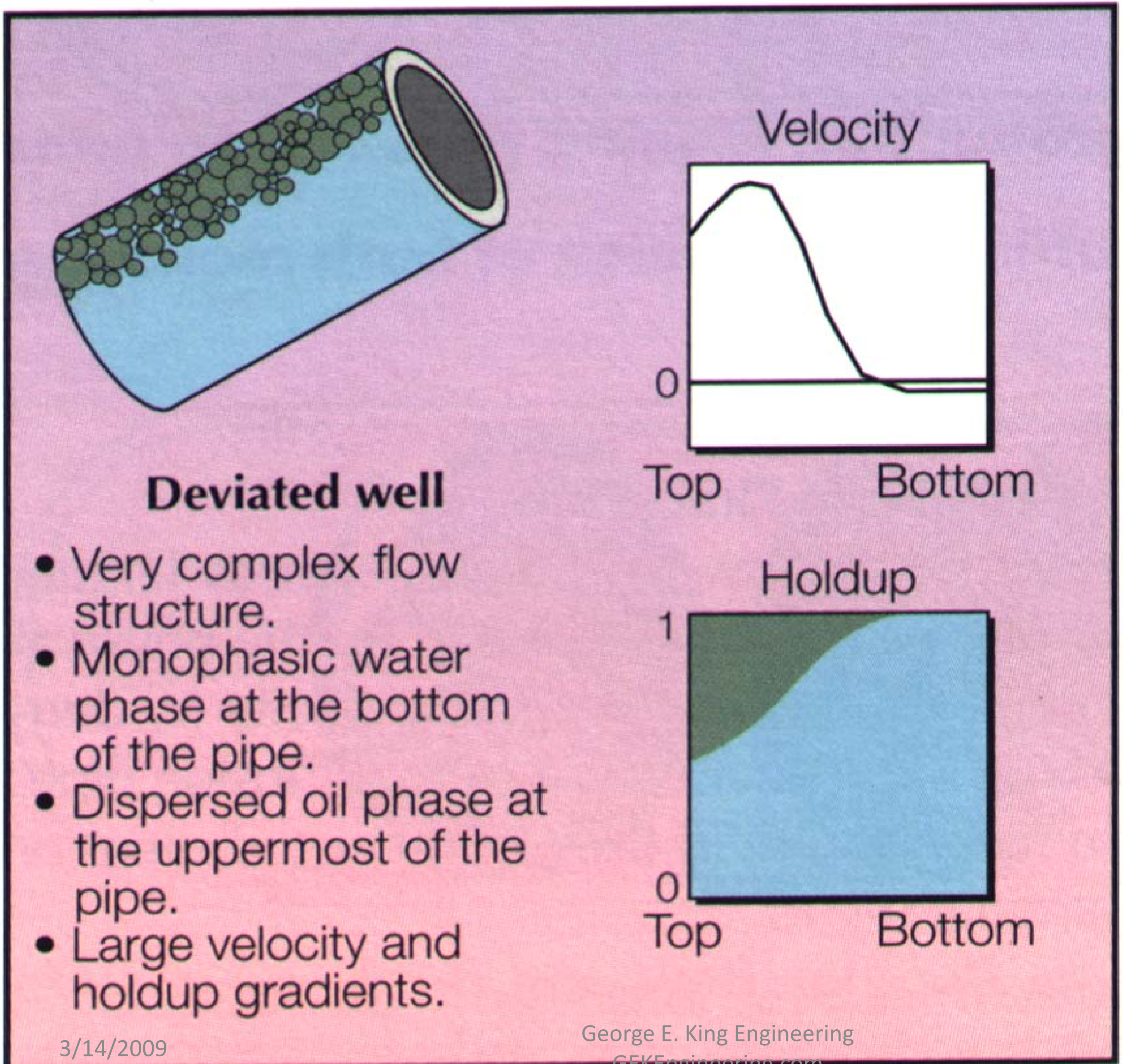
Method	Description	Pros	Cons
Soap Injection	Forms a foam with gas from formation and water to be lifted.	Does not require downhole mods.	Costly in vol. Low water flow. Condensate is a problem.
Compression	Mechanical compressor scavenges gas from well, reducing column wt and increasing velocity.	Does not require downhole mods.	Cost for compressor and operation. Limited to low liquid vols.
Velocity Strings	Inserts smaller string in existing tbg to reduce flow area and boost velocity	Relatively low cost and easy	Higher friction, corrosion and less access.

Lift and Unloading Options

Method	Description	Pros	Cons
Cycling / Intermitter	Flow well until loading starts, then shut in until pressures build, then flow.	Cheap. Can be effective if optm. No DH mods.	Req. sufficient pressure and automation (?)
Equalizing	Shuts in after loading. Building pressure pushes gas into well liquids and liquids into the formation.	Will work if higher perm and pressure. No downhole mods.	Takes long time. May damage formation.
Rocking	Pressure up annulus with supply gas and then blow tubing pressure down.	Inexpensive and usually successful.	Req. high press supply gas. Well has no packer.
Venting	Blow down the well to increase velocity and decrease BHFP.	Cheap, simple, no equipment needed.	Not environmentally friendly.

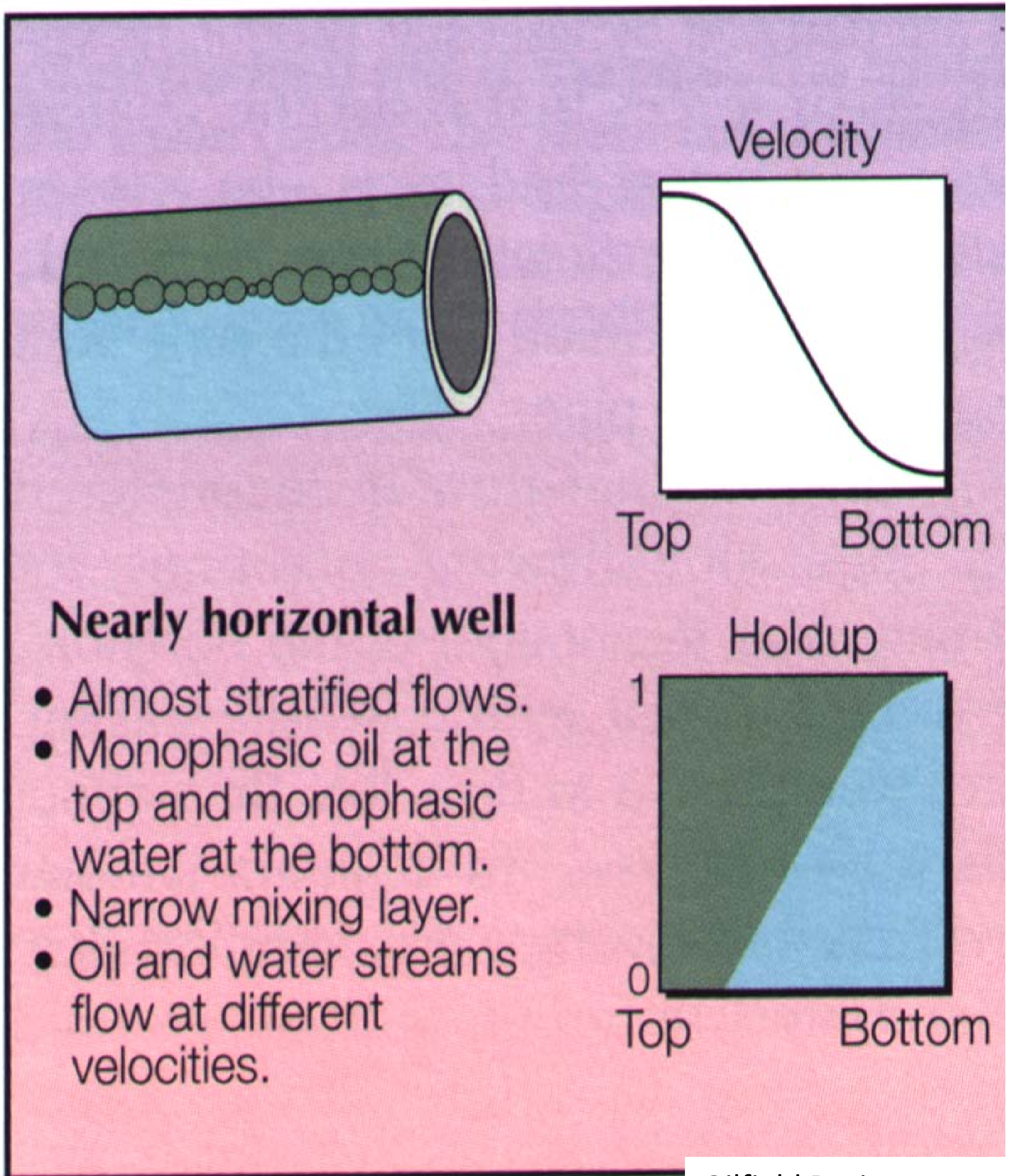


Oilfield Review



Note the flow velocity difference between the top and bottom of the pipe.

Oilfield Review



Oilfield Review

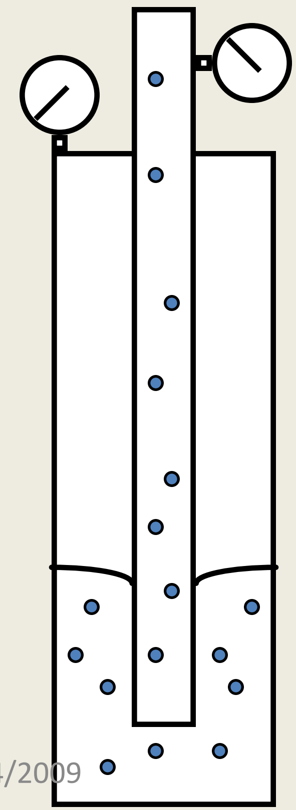
Flow in highly deviated wells is much harder to predict than flow in near vertical wells. In near vertical wells, hindered setting keeps the liquids, solids and gas mixed and all moving upward as long as the gas rate is sufficient to achieve critical rate. In deviated wells however, the lighter fluid separates to the top of the flow channel and the liquids may "percolate" along the bottom in the 30 to 60 degree range, developing liquid holdup and back pressure.

Unloading Techniques

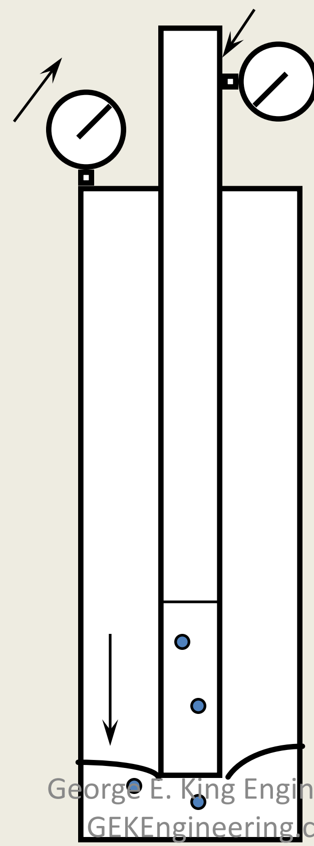
- Stop-cocking - temporarily shut in and re-open well. Shut-in forces free gas into solution and some liquid back into the formation. Opening the well allows gas to breakout of liquids and the formation and lift liquids.
- Rocking - pressuring up with supply gas and then opening the well. This works for wells without packers where the annulus can be used as a pressure charge chamber.
- Soap sticks or foamers – decrease hydrostatic head by tying liquids up in a 3 lb/gal foam
- conventional lift (power adders) - pumps
- flow improvers - gas lift and plunger
- reduce the tubing diameter to get velocity above critical velocity to lift liquids – examples are velocity strings

Slugging

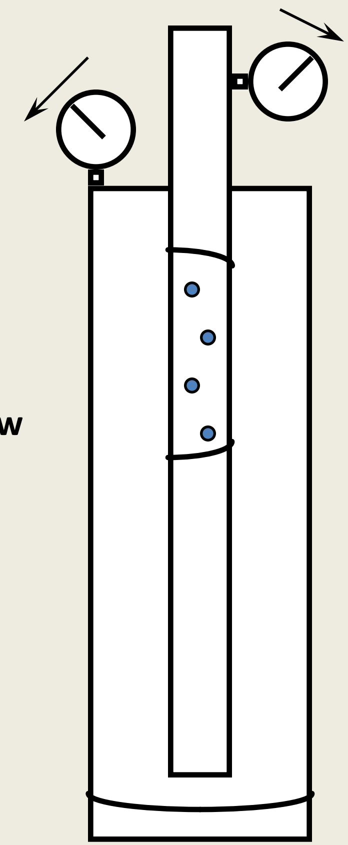
- Usually occurs where a well has no packer or a long tail-pipe (large annular storage).



1. normal flow, but gas is building up in the annulus



2. gas press built up, inflow slows and tbg loads up.



3. casing gas flows into tubing, venting annul. pressure but causing a slug

What the problem with a slug?

- Non steady state flowing systems are hard on surface separator facility – (complete separation depends on a certain residence time in the separator)
- Varying density of the lifted liquid exerts a backpressure on the formation and decreases flow:
  - 10,000 ft of gas exerts 1000 psi
  - 10,000 ft of oil exerts 3640 psi
  - 10,000 ft of salt water exerts 5200 psi

Other Slugging Causes

- Large tubulars - allows gas to separate and slip through the tubing.
- Elevation changes in deviated wells (especially through the Boycott settling range of 30^o to 60^o
- Non-steady flow conditions at feed in points (flood breakthrough)
- Leaks
- Stimulation fluid backflows

Slugging and Heading Solutions?

- Insert or velocity string?
- Smaller tubing?
- Lined tubing?
- Less annular volume?
- Annular dump valve?

When do you need lift?

- Do an IPR analysis
- Do a nodal analysis on the effect of back pressure.
- Look for slugging, surging effects
- Will adding lift make an economic impact on production?