Introduction to Plunger Lift

Prepared for: SPE Queensland
Brisbane
Who are Well Master and PLS Technologies?

For over three decades, Well Master’s mission has been to enhance gas well production by providing oil and gas producers practical means to maximize well productivity and extend well life, controlling costs and maintaining environmental responsibility. Today, we are technology leaders in plunger lift, bringing proven products, innovation, new understanding and training to the industry.

PLS Technologies are the Well Master representatives for Australia and New Zealand. Our partnership was established in mid-2014.
The “Real” Task in Gas Well Operations: Managing Bottom Hole Flowing Pressure

Flow into the wellbore only occurs if $P_{BH} < P_F$
The “Real” Task in Gas Well Operations: Managing Bottom Hole Flowing Pressure

**Maximum** flow into the wellbore occurs if $P_{BH} << P_F$

**Zero** flow into the wellbore occurs if $P_{BH} \geq P_F$

This is the essential definition of the Inflow Performance Relationship (IPR) curve.

Therefore, to manage the inflow and thereby our rates of production, we must focus on managing the bottomhole flowing pressure $P_{BH}$
Vogel Inflow Performance Relationship Curve

The next page shows the Vogel Inflow Performance Relationship Curve

What it means:

The lower the flowing or producing bottom hole pressure (PBHP) relative to the formation or static pressure (SBHP), the higher the production rate from that well. We can simplify this further by just monitoring Casing Pressure in a packerless completion.

In other words: If we can remove most of the liquid from the well that causes a back pressure to be exerted against the formation, the easier it is for gas and liquids to enter into the well bore.
The goal is to reduce the producing bottom hole pressure (you will actually be watching casing pressure in a packerless completion) to a minimum practical level while maintaining stable well operation. Moving from 70% to 85% efficiency above means 15% more gas and liquid from a particular well. This can be readily achieved with most “smart” controllers.
When Would We NOT Want the Lowest Possible Flowing Bottom Hole Pressure?

Multiple zones open when one or more of those produce excess water at lower pressures

Excess flowrate may draw in sand

Reservoir management. Best practices include drawing down our bottom hole pressures at a controlled rate to minimize formation and skin damage.

In the above cases there will be a minimum backpressure to maintain in order to prevent excessive inflow rates.
What Are Our Artificial Lift Solution Options?

Liquid Removal Capacity for Various Forms of Artificial Lift (bbls/day)

<table>
<thead>
<tr>
<th>Artificial Lift</th>
<th>Typical</th>
<th>Approx. Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plunger Lift</td>
<td>1 – 100</td>
<td>250</td>
</tr>
<tr>
<td>Rod Pump</td>
<td>5 – 1500</td>
<td>6000</td>
</tr>
<tr>
<td>PCP</td>
<td>5 – 2200</td>
<td>4500</td>
</tr>
<tr>
<td>ESP</td>
<td>100 – 30,000</td>
<td>40,000</td>
</tr>
<tr>
<td>Hyd. Jet</td>
<td>300 – 4000</td>
<td>15,000</td>
</tr>
<tr>
<td>Gas Lift</td>
<td>100 – 10,000</td>
<td>30,000</td>
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</tbody>
</table>
Why Use Plunger Lift as an Artificial Lift Solution?

Gas wells vs. oil wells in loaded conditions

- primary difference is that gas wells provide us with an opportunity to use a natural, compressed gas source to act as a pneumatic driver to lift liquids

- oil wells are hydraulic systems, flowing an incompressible fluid, which is best handled through pumps, often losing efficiency as gas volumes increase

- any liquid-producing gas well needs sufficient gas relative to the amount of liquid in order to sustain the pneumatic requirements of plunger lift (Gas to Liquid Ratio or GLR)

- if minimum GLR requirements are met, then Plunger Lift has a number of advantages, including capital and operating cost over other methods
Why Use Plunger Lift as an Artificial Lift Solution?

Plunger lift vs other forms of artificial lift

Many other forms of artificial lift require an external energy source, e.g.:

- Gas Lift (requires compressor with gas or electric drive)
- Rod Pump (requires gas or electric drive)
- Electric Submersible Pumps, Progressive Cavity Pumps (electric drive)

Alternatively, chemical methods can be used (foamer/soap)

All of the above methods are MORE COSTLY than Plunger Lift, both from a capital and operating standpoint. Pumping options are typically in the order of 10X more expensive.
Plunger Lift Usage Is Growing

- Favorable economic and environmental factors have always existed versus other deliquification methods

- Stigma of the past as a “black art”, not well understood and with high risk of downtime relegated the technique primarily to marginal gas wells

- Exceptionally strong growth in use of wellhead automation, especially over the past 15 years has allowed remote monitoring and operating parameter adjustment

- Good algorithms embedded in automation systems removes much of the “black art” and allows the system to self-tune

- “Off-the-shelf” automation solutions exist from plunger system suppliers (Modbus enabled) and major instrumentation companies (Emerson/Fisher, ABB/Totalflow, etc.) incorporate plunger control into electronic flow meters (EFM’s)
Primary Benefits of Plunger Lift

Economic

- Capital Cost: Approx. AUD$10,000 to $30,000
- Operating Costs: Approx. AUD$10,000 to $15,000 annually

Environmental

- uses natural pressure of gas in the ground as a driver
- no external power required
- minimizes venting to atmosphere
What is in a Plunger Lift System?
What is in a Plunger Lift System?

- **Lubricator**: (Access point to well for normal operations)
- **Solar Panel**
- **Master Valve**: (Isolates well for shut-in or service)

**Diagram Details**:
- **Controller**
- **Motor Valve**
- **Solar Panel**
- **Sales Valve**
- **Sales Line**: (Production to separator and sales or to tank if unloading)
- **Surface Casing**
- **Production Tubing**
- **Plunger**
- **Downhole Spring Assembly**
- **Seating Nipple**
- **Cement Sheath**
- **Production Formation**
- **Perforations**
What is in a Plunger Lift System?
What is in a Plunger Lift System?
The Principle of Plunger Lift

Plunger Lift is a Pneumatic System

→ This means it is gas-driven, which gives us the advantage of the compressibility of the gas to store kinetic energy, and to release this in a manner that we can use to lift liquid

→ The plunger acts as a physical interface between the liquid above and the gas below, minimizing liquid dropback and making more efficient use of the gas

→ Plunger lift originated as a way to augment intermitted wells but both continuous-run and intermittent operation is common today
Easy to understand!

This is great! I'll be going fishing in no time!
Except Mother Nature Reduces Our Compressor Size Every Day! = Decline Curve

Guess this will take longer than I thought!!
Continuous Run Plunger
Plungers Can Be Effective in Vertical and Horizontal or Inclined Wells
Liquid Loading Over Time Without Artificial Lift

- Surface condition
- Stable flow
- Unstable flow
- Stable flow
- Well dead

Initial production

Rate

Decreasing gas rate

Time
Why/When Do We Install Plunger Lift?

The well does not have the ability to maintain the required gas velocity to lift liquids. Flowing below some measure of critical rate or some other measure of instability.

Can be used as a method to keep tubing clean. ie – paraffin, sand or scale issues

Should be installed prior to production falling off normal decline curve. Usually minimize production losses if done this way. The conditions for onset of can be calculated and predicted to anticipate timing.

After an install is uplift good news? Sure, BUT does it mean you have been flowing below the decline curve for too long???
Typical Gas Well Production Decline Curve

Optimum to return well to the original production decline
Example

Production vs Time

Liquid Loading Point

Install High Speed Continuous Flow Plunger

Problems Keeping High Speed Plunger Running
Critical Rate Considerations

By definition: “The gas rate for a given set of conditions at which liquid droplets are suspended”.

We often see Critical Rate and Critical Velocity terms used interchangeably. Critical Rate is actually:

\[ C_R = V_C \times A \]

Where \( A \) = cross sectional area of tubing

Critical Velocity \( (V_C) \) is the gas velocity at which the forces of Gravity and Drag are equal. Droplets are suspended and not moving vertically up or down at this rate!
Critical Flow Rate for API Tubing - Lower Pressures

Instantaneous Flow Rate (mcf/d)

Flowing Pressure at Wellhead (psi)

- 2-1/16"/1.75
- 2-3/8"/1.995
- 2-7/8"/2.441
Even in the annular/mist flow regime you can have liquid going up in droplet form and down in the annular form!

You will see loading begin at the bottom of the well as casing pressure flattens out and starts to increase, regardless of what the Turner number is at surface!
1 well – multiple considerations?

Critical rate assuming surface conditions only – most common practice

Input well conditions into ProdOP for example – shows well reaches critical below 3722 ft. and therefore begins loading much earlier than surface prediction indicates.
Loading is best predicted by the J-Curve

1. Create the J-Curve

2. Draw a line through the extended right side down and to the left

3. Look at the area where the tangent breaks from the curve.

4. Determine the range where flow regime transition begins

Graphic created in ProdOp (Dr. James Lea, PLTECH)
What is our battle?

We want to maintain flow conditions like this…

…But left alone to flow by itself, our well wants to do this…

The height of the liquid column is the ENEMY of production.
Different shapes and volumes of vessels hold different volumes of liquid and therefore different mass or weight of liquid. The hydrostatic head or pressure at the base of each vessel is determined by the height of the liquid column, not the volume or the mass of the liquid. Each of these vessels has the same pressure at the bottom. In a gas or oil well, the pressure exerted on the formation is determined by the pressure of gas in the tubing, plus the height of the liquid column. The diameter of the tubing does not affect the pressure at the bottom.
In working out his principle, Blaise Pascal showed dramatically how force can be multiplied with fluid pressure. He placed a long thin tube of radius \( r = 0.35 \, \text{cm} \) vertically into a wine barrel of radius \( R = 29 \, \text{cm} \), see the figure. He found that when the barrel was filled with water and the tube filled to a height 12 m, the barrel burst.

(a) Calculate the mass of the water in the tube.

\[ \text{kg} \]

(b) Calculate the net force on the lid of the barrel just before rupture.

\[ \text{N (upward)} \]
Pascal’s Experiment

\[ V = b \times h \]

\[ h = 12m = 1200cm \]
\[ b = \pi r^2 \]
\[ b = 3.14 \times (0.35)^2 \text{ cm}^2 \]
\[ b = 0.385 \text{ cm}^2 \]
\[ V = 461.8 \text{ cm}^3 = 0.4618 \text{ L} \]
\[ m = p \times V \]
water density is \( p = 1 \text{ kg/L} \)

(a) Weight of water in the tubing \( m = 0.4618 \text{ kg} \) (= 1.17 lbs.!!)

at the bottom of the tube:
\[ F = m \times g = 9.81 \times 0.4618 = 4.53 \text{ N} \]
which acts on area \( b = 0.385 \text{ cm}^2 \)

but the barrel lid has area
\[ B = \pi R^2 = 3.14 \times 29^2 \]
\[ B = 2642.08 \text{ cm}^2 \]

so force on entire lid is
\[ F = 4.53 \times 2642.08/0.385 \]
\[ F = 31087.3 \text{ N} \]

(b) which is equivalent to weight of mass \( M = F/g = 3169 \text{ kg} \) (= 8,049 lbs.!!) or just over three tons. (quite amazing considering that only 0.5L of water was used)
We often see problems with wells when we reduce our flowing pressures by a few psi, even though the well may be flowing at several hundred psi. Why is it so sensitive?

If we asked you to stand downstream of a dam while we lowered the pressure in the lake by 10 psi, do you think this would be a good idea?
10 psi is equivalent to 23 feet of fresh water head. So lowering our lake pressure by 10 psi means lowering the dam by 23 feet. It may be dangerous to do that all at once (so don’t stand downstream!). The best thing to do would be to lower the level gradually.

Similarly in our wells, we often increase flow from a liquid producing zone as we reduce the flowing bottom hole pressures. A sudden drop of even a few psi may cause a wet zone to have its “dam” lowered, bringing on a flood of liquid. Better to either hold backpressure or reduce flowing pressures gradually. This is also true if we wish to control how quickly we draw on our formation for reservoir management.
The Life Cycle Approach

- Fastest, Continuous
- Fast, Non-Continuous
- Moderate
- Slow

Decline in Rate vs time

IPS Pacemaker
FB Super Flow
WMC Venturi
Viper
WMC Viper
IPS Ultra Seal
TT Brush
Consider the four scenarios below. Each represents a well with a different casing pressure build rate, from fast to slow. F&G predicts 250 psi required to lift a certain slug of liquid. The well is ready to run when it builds up to that pressure.
Volume or Velocity?

Most often plunger recommendations have been based on the daily rate of the well – this can be very misleading!

You must consider the flowing tubing pressure to get the plunger selection right as this impacts gas velocity in the tubing.

Consider the following example where we look at a 250 mcf/d well at three different flowing tubing pressures…. Pay close attention to the gas velocity!
STEP 1 – BUILD WELL BORE
Step 2 – Input Operating Conditions
Case 1: 250 MCF/D @ 1000 PSI  Flowing Tubing Pressure

Bottom hole velocities are too low to run a plunger. Shut-in to increase initial flow rate to minimum of 900 mcf/d instantaneous rate when well opens. This will give a bottom hole velocity near 5 ft./sec. Choose conventional type plunger such as a pad or lightweight solid.
Bottom hole velocities strong enough to run a plunger with some shut in time. Match the plunger fall rate to the casing pressure build rate. Most likely select quick drop or medium orifice Venturi.
Case 3: 250 MCF/D @ 50 PSI  Flowing Tubing Pressure

Bottom hole velocities are high enough (>10 ft/sec) to support a continuous run plunger. Select a continuous run type such as an Eagle or large orifice Venturi with minimized off time.
Fall Velocities

There are widespread misconceptions surrounding fall velocities

Be cautious using “rules of thumb”

Pressure can have a larger impact on fall velocities than tool selection

Inflow can have a large impact on fall rates

If using fast falling plungers/bypass ensure BHS can handle “worst case scenarios”

Fall velocities will change if gathering system pressures change
Example: Using 200 psi avg tubing pressure, get fall rates for each plunger type. If we have an 8000’ well, the time to bottom in gas only:

- **10mm**: 650 fpm → 12.3 min
- **8mm**: 510 fpm → 15.7 min
- **4.7mm**: 400 fpm → 20 min
- **Viper**: 350 fpm → 22.9 min
Look again at the four examples from before with the potential plunger selection added. This is how we match up the plunger selection with the time it takes for the well to be ready to lift a given slug size of liquid.

- **Continuous or By-pass**
  - **8 minutes**

- **Bypass or 10 mm Venturi**
  - **14 minutes**

- **8 or 4.7 mm Venturi or Viper**
  - **32 minutes**

- **4.7 mm Venturi, Barstock or Pad**
  - **52 minutes**

Foss & Gaul PcMax
1. Choose tubing size from the tubing selector

2. Choose plunger type from the plunger selector

3. Input average tubing pressure during close over entire well depth, approximate average temperature and SG of the gas and liquid

4. Input well depth to the bottom stop, average liquid and number of trips daily

<table>
<thead>
<tr>
<th>Tubing Pressure (psig)</th>
<th>300</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (F)</td>
<td>150</td>
</tr>
<tr>
<td>SG of Gas</td>
<td>0.65</td>
</tr>
<tr>
<td>SG of Liquid</td>
<td>1.0</td>
</tr>
<tr>
<td>Depth to EOT (ft.)</td>
<td>8000</td>
</tr>
<tr>
<td>Avg. Liquid/day (bbls)</td>
<td>10</td>
</tr>
<tr>
<td>Trips per day</td>
<td>20</td>
</tr>
</tbody>
</table>

Fall Rate in Gas (ft/min) 248.41

Fall Rate App for iOS and Android is Available for Free
5. Results are calculated to give fall rates and times in gas and liquid plus total time to bottom. Note that these are best estimates and a 5-10% safety factor is recommended.

6. Instructions and FAQ’s available
Pinedale Anticline Wyoming, High Pressure, low velocity well, switch from Barstock to 4.7 mm Venturi, 60 Day window, typical result

Casing P drops 100 psi
Gas up 50 mcf/d

Mesa 3 Current Flow Rate (F_CV) 111.11  Hist.PDSCADA.M00006592_VolumeFlowRate.F_CV
Mesa 3 Tubing Pressure (F_CV) 725.30  Hist.PDSCADA.W00006592_TubingPressure.F_CV
Mesa 3 Casing pressure (F_CV) 868.03  Hist.PDSCADA.W00006592_CasingPressure.F_CV
Mesa 3 Volume Yesterday (F_CV) 131.52  Hist.PDSCADA.M00006592_VOLUMEYDAY.F_CV
Mesa 3 Pressure (F_CV) 533.61  Hist.PDSCADA.M00006592_STATICPRESSURE.F_CV
Change from Barstock to 8 mm Venturi (2-7/8”)

Flowrate increase from 14 to 18.2 e3m3/d (494 to 643 mcf/d)

Tubing Pressure increases by 300 kpa (44 psi)
Volume increases with more on time...

Casing pressure declines...
Casing pressure continues to decline and production is up over 25%...
Directional and Horizontal Wells
Liquid Loading

Knowledge base is from vertical wells, but present and future is non vertical

- Liquid-gas mix separates due to gravity and the rate is a function of the projected horizontal area
- Increases liquid loading down hole
- Flow structure changes as tubing deviates from vertical
- Deviated sections are more difficult to unload

\[
\text{Area} = \frac{\text{Vertical Area}}{\cos(\text{angle})}
\]
Critical Rate

• Not unloading at critical rate, efforts to establish Turner/Coleman correction factors have given limited success
• Annular flow always present
• Gas less effective in lifting
• Separation of gas from liquid in the inclined and horizontal sections are very problematic
Liquid Loading

Plunger Lift

• Interface to lift liquid
• Turbulent vs Mechanical seal
• Drag driven (Cd) vs Displacement models (Foss & Gaul type)
• Additionally, new set of problems today posed by horizontal and directional wells

Drag model best predicts turbulent seal
Displacement model may be best predictor for mechanical seal
Plunger Issues in Directional Wells

Turbulent Seal (Solid)

- Lays against tubing, not centered, uneven wear
- Inconsistent behavior due to high amount of gas blow-by

Gas velocity profile from CFD (red is fast, blue is slow)
Plunger Issues in Directional Wells

Mechanical Seal (Pad)

• Pads collapse on lower side as springs compress
• Rowlan et. al 2013 finding: velocity increase from 230 to 450 fpm upon 20+ degree deviation
• Loss of lifting efficiency in deviated tubing due to high gas blow-by
• Increased slippage makes displacement models such as Foss and Gaul less reliable
Plunger Design for Directional Wells

Design Philosophy & CFD

Dynamic Turbulent Seal (Solid)

- Lateral jets induce rotation
- Fluid-film bearing effect
- Even wear, consistent behavior even in inclined tubing
Plunger Design for Directional Wells

Design Philosophy & CFD

Enhanced Mechanical Seal (Jetted Pad)

• Fluid-pressure “spring” in addition to mechanical springs
• Expands pads, restores mechanical seal
• Jetting creates unbalanced load when tool is inclined, rotates tool
• Consistent performance at deviations above 80 degrees (non-jetted capable to 15-20 deg)
• Long-travel pads can pass easily through X-profile
Plunger Design for Directional Wells

Field Results

Dynamic Turbulent Seal (Solid)

Arrival Histogram Data from horizontal well study by a large Canadian producer

Tubing set at 60 degrees

The narrower range of arrival speeds indicates much greater consistency

Non-ported: Erratic arrivals  
Ported: More consistent arrivals
Summary

✓ To be effective gas well operators, we must be good flowing bottom hole pressure managers

✓ Liquid column height is the enemy of production

✓ Onset of liquid loading is better predicted with the J-Curve than Critical Rate

✓ Optimizing wells often requires cycling the plunger as frequently as the well will allow

✓ Plungers should be selected based on well readiness

✓ Horizontal and inclined wells flow differently than vertical wells

✓ Horizontal and inclined wells operate better with plungers designed to operate under those special conditions