Deliquification Basics

3rd European Conference on Gas Well Deliquification
September 15-17, 2008
Agenda/Instructors

• Safety
• Is my gas well impaired?
• Break
• How impaired is it?
• Break
• What can I do about it?
• Exercises
• Wrap Up!

Your Instructors Today

Alison Bondurant is a Petroleum Engineer in BP’s E&P Technology group & is the North American Gas Deliquification Network Lead.

Bill Hearn is the Manager of Weatherford’s Plunger Lift business unit.
Safety

Hurricanes
Importance of Deliquification
World-wide Market
Objectives of Today

At the end of this course, you will understand:

• Is my well impaired?
• How impaired is it?
• What can I do about it?
Objectives of Today

At the end of this course, you will understand:

• Is my well impaired?
• How impaired is it?
• What can I do about it?
Is My Well Impaired?

Liquids Impair a Well Below Critical Velocity

Basically, Critical Velocity is how fast rain drops (about 30 ft/s)
Liquids in a Gas Well Bore

- **Entering through the perfs:**
  - Free formation water
    - Water and gas come from the same zone
  - Water produced from another zone
  - Water coning
    - If gas rate is high enough, water may be “sucked” to perforated zone from a water zone below
  - Aquifer Water
    - Pressure support from a water zone may lead to the water zone “traveling” to perforations

- **Forming in the wellbore:**
  - Condensation. Resulting water will be fresh and maximum quantity can be calculated. (Often very corrosive.)

- **Hydrocarbon Liquids (condensate):** All the above can happen but most common is from same zone or condensation in wellbore. Typically 5-80 BBL/MMSCF.
Typical Gas Well Decline

Any gas well will flow to here..

But if the well makes liquids, and the “raindrops” fall, they will accumulate and the well will die.

A well with no liquids (rare) will flow like this...

Rate, MSCFD

Percentage of Potential Well Life

Dry Well Rate MSCFD
Minimum for 2-3/8” Tubing
“Wet” Well Rate MSCFD
Typical Gas Well Progression

Rate, MSCFD

Flowing to here …

... then use well’s energy …

... then add power & $

Percentage of Potential Well Life
Liquids in a Gas Well

• REMEMBER: In liquid loading, Gas Velocity is the elephant; liquids rate is the mouse.

• Reducing liquids rate downhole can make deliquification easier, but without enough gas velocity any liquid in the wellbore will pool up.
### Vertical Flow Regimes

**ANNULAR MIST**
- Gas phase is continuous
- Pipe wall coated with liquid film
- Pressure gradient determined from gas flow

**SLUG-ANNULAR TRANSITION**
- Gas phase is continuous
- Some liquids as droplets in gas
- Liquid still affects pressure gradient

**SLUG**
- Gas bubbles expand as they rise into larger bubbles and slugs
- Liquid film around slugs may fall down
- Gas and liquid affect pressure gradient

**BUBBLE**
- Tubing +/- completely filled with liquid
- Free gas as small bubbles
- Liquid contacts wall surface, bubbles reduce density

**Decreasing Velocity: Lower Gas Flow or Higher Pressure**
Below critical gas rate liquid cannot be effectively transported from the wellbore.

Below this rate, liquids will settle to the bottom of the tubing. Production is decreased and, if not corrected, the well will die.
Liquid Loading Cycle
Flowing Well

- Flow Rate Declines
- Velocity in Tubing Drops
- Settling Fluid Creates Back Pressure and Continues to Drop Flow Rate

A well loads up when it is FLOWING!
Predicting Liquid Loading

- Droplet Model
- J-Curve Method
Predicting Liquid Loading
Droplet Model

- Droplet weight acts downward & Drag force from the gas acts upward

- **Critical Velocity (theoretical)** = When the droplet is suspended in the gas stream

- **Critical Velocity (practical)** = The minimum gas velocity in the tubing required to move droplets upward.

- Turner et al. developed correlation to predict this Critical Velocity assuming the droplet model

![Diagram showing the forces acting on a water droplet in a gas flow system.

Gravity

Drag

Gas Flow

Water Droplet]
Critical Velocity \((V_c) = 1.92 \frac{\sigma^{1/4}(\rho_{\text{Liquid}} - \rho_{\text{Gas}})^{1/4}}{\rho_{\text{Gas}}^{1/2}}\)

Correlation was tested against a large number of real well data having surface pressures >1000 psi.

Standard Assumptions that “Simplify” Turner Equation:

- Surface Tension (water): 60 dynes/cm
- Surface Tension (condensate): 20 dynes/cm
- Water Density: 67 lbm/ft³
- Condensate Density: 45 lbm/ft³
- Gas Gravity: 0.6
- Gas Temperature: 120°F
- 20% upward adjustment – In order to match field data

“Simplified” Turner Equation:

\[ V_c = C \frac{(\rho_{\text{Liquid}} - 0.0031p)^{1/4}}{(0.0031p)^{1/2}} \]

\(C = 5.34\), water  \(C = 4.02\), condensate, \(p \geq 1,000\) psi.
Critical Gas Flow Rate is the flowing gas rate necessary to maintain the Critical Velocity.

Critical Gas Flow Rate Equation

\[ Q_{(MMCFD)} = \frac{3.06PV_cA}{Tz} \]

- \( P \) = Flowing Tubing Pressure
- \( V_c \) = Critical Velocity
- \( A \) = X-Area Tubular Flow Path
- \( T \) = Flowing Temp °R
- \( Z \) = Z Factor
• **Velocity** - depends on the *rate* of gas, the cross-sectional *area* of the pipe, & the *pressure*.
  - *All other factors are relatively unimportant.*

• **Critical Velocity** - speed needed to lift droplets depends on the *pressure*.
  - It is relatively insensitive to the amount of liquid.
  - Since we’re almost always dealing with natural gas and water, those factors are fixed.

• So, the **Minimum Unloading Rate** can be closely predicted knowing only *pressure* and *pipe size*. 
Typical Minimum Unloading Rates
based on Turner Correlation
Liquid Loading: Coleman Equation
Surface Pressures < 1,000 psi (70 bar)

Critical Velocity \( V_c \) = 1.593
\[
\frac{\sigma^{1/4}(\rho_{\text{Liquid}}-\rho_{\text{Gas}})^{1/4}}{\rho_{\text{Gas}}^{1/2}}
\]

Coleman et al. equations are identical to Turner et al. equations:

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“Simplified” Coleman Equation:

\[
V_c = C \frac{(\rho_{\text{Liquid}}-0.0031p)^{1/4}}{(0.0031p)^{1/2}}
\]

C = 4.434, water \quad C = 3.369, condensate, p<1,000 psi.

Coleman eliminates 20% adjustment
Critical Flow Rates

Wellhead Pressure vs. Flow Rate for different casing and tubing configurations:

- 1.00"/0.826"
- 1.25"/1.076"
- 1.50"/1.310"
- 2.0"/1.78"
- 1.90/1.61"
- 2 1/16"/1.75"
- 2 3/8"/1.995"
- 2 7/8"/2.441"
- 3.5"/2.867"
- 4.5" 11.6 lb/ft
- 5.5" 20 lb/ft
- 7.0" 26 lb./ft
- 4.5" Casing w/ 2 3/8" Tubing
- 5.5" Casing w/ 2 7/8" Tubing
- 7.0" Casing w/ 3 1/2" Tubing
Predicting Liquid Loading
J-Curve Method

- Also called “VLP” (Vertical Lift Performance) or “Tubing Performance Curve” (TPC)
- Shows the relationship between the total tubing pressure drop & surface pressure, with the total flow rate.
- Tubing pressure drop is sum of:
  - Surface pressure
  - Hydrostatic pressure of the fluid column (gas & liquid)
  - Frictional pressure loss resulting from the fluid flow
Predicting Liquid Loading
J-Curve Method

Family of J Curves at 200 psig FTP, 30 BBL/MM Water, 10000', Grey's Modified

<table>
<thead>
<tr>
<th>Tube</th>
<th>Min FBHP psig</th>
<th>Bottom of J, MSCFD</th>
<th>Coleman Crit. Rate MSCFD</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.380&quot; ID</td>
<td>675</td>
<td>230</td>
<td>175</td>
</tr>
<tr>
<td>2.041&quot; ID</td>
<td>540</td>
<td>580</td>
<td>380</td>
</tr>
<tr>
<td>2.441&quot; ID</td>
<td>510</td>
<td>900</td>
<td>540</td>
</tr>
<tr>
<td>2.992&quot; ID</td>
<td>480</td>
<td>1500</td>
<td>820</td>
</tr>
<tr>
<td>3.920&quot; ID</td>
<td>450</td>
<td>3000</td>
<td>1400</td>
</tr>
</tbody>
</table>

..while this part of the J-Curve is due to friction.

This part gives higher BHP due to liquids accumulation...

Note the differences!
Therefore:

Velocity lowest at the bottom of the hole

As the gas gets less dense, you have to have more velocity to drag the liquid upwards.
More Liquids = More Loading…Right?

Not as much as you’d think…

Over Range of 5-100 BBL/MMSCF of water (2000%):
- Minimum rate varies less than 40%
- & FBHP varies 50 to 100% (by Grey’s correlation).

Grey’s correlation: gives a more sophisticated estimate of minimum critical rate that accounts for the amount of liquids.
OLGA Same response…only different

- OLGA is a finite element model, modeling the droplets & their interactions.
- “Should” be more accurate in theory than Grey’s… but don’t really know
Confirming Liquid Loading

If you are below critical velocity, you are probably have some accumulation of liquid in the well.

To confirm:
- Observed slugging from well
- Rapid increase in decline rate
- High casing/tubing differential (only if don’t have a packer)
- Increase in liquids
- Can confirm with wireline gauge
Sharp Decline from Smooth Curve

Decline with & without Liquid Loading

- Expected
- Actual with Loading
Classical Gas Well Loading
Gas Rate Declines as Water Increases

Water Shut-off performed

Classic Water Drive
- Daily production does not mean that the well is "flowing" or "unloaded"
- Field Automation is helpful, but you can miss the REST OF THE STORY
- Daily Automation Gas Rate = 200mcf/d....Is that all it can make?
Increase of Casing Minus Tubing Pressure with Time

For wells without a production packer

Increase in Casing minus Tubing Pressure vs. time indicates loading

Casing Pressure

Tubing Pressure

Csg – Tbg Psi

Time
Pressure Survey Reveals Gradients in Tubing Pressure

Results of Pressure Survey

Depth

Pressure

Gas

Liquid
• **Depth of Tubing**
  - Must analyze liquid loading tendencies at locations in the wellbore where production velocities are the lowest.
  - Gas wells can be designed with the tubing hung off the well far above the perforations
  - Therefore, lowest velocity is in the casing

• **Horizontal Wells**
  - Correlations cannot be used
Liquids Impair a Well Below Critical Velocity

Calculation of critical unloading rate:
- Screening: Turner (>1000psi), Coleman (<1000psi)
- Modeling: J-curves

Observations:
- Slugging from well
- Rapid increase in decline rate
- High casing/tubing differential
- Increase in liquids
Objectives of Today

At the end of this course, you will understand:

✓ Is my well impaired?
• How impaired is it?
• What can I do about it?
How Impaired is the Well?

Depends on:

- Amount of liquid accumulated >> BHP
- “Productivity Index” $\Delta$MSCFD/ $\Delta$psi
Example 1 - How Much Gas?

Southern North Sea Gas Well Foamer Trial

<table>
<thead>
<tr>
<th>BHP psi</th>
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<tr>
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Well B DH Gauge Data

Well B DH Pressure and DH Temperature

Plant trip due to high water production on well

Surfactant injection

Plant trip and liquid falling back

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Well B DH Gauge Data

Well B DH Pressure and DH Temperature

Plant trip due to high water production on well

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Plant trip and liquid falling back
Example 2 - How Much Gas?

Wyoming, USA Capillary String (Foamer Injection)

- No measurement was made of fluid level or Bottomhole Pressure
- But based on experience with other wells in the area, probably represented a 100-300 psi drop in FBHP.

Gain was **400 MSCFD** or about **25%**
Goal: Increased Production ($)

- Our goal isn’t to reduce liquid level. Our goal is to improve gas production.
- Case 1 adds 12,000 MSCFD on about 350 psi change but Case 2 only adds 400 MSCFD on 100-300 psi change.
- How do you know how much additional gas you’ll get?
### Impairment Varies!

Same rate and pressure at loading...

<table>
<thead>
<tr>
<th></th>
<th>Impaired (medium resistance)</th>
<th>Unloaded (low resistance)</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>MSCFD</td>
<td>BHP psi</td>
</tr>
<tr>
<td>High Reservoir Pressure, Low Perm</td>
<td>850</td>
<td>720</td>
</tr>
<tr>
<td>Low Reservoir Pressure, High Perm</td>
<td>870</td>
<td>750</td>
</tr>
</tbody>
</table>

..gives vastly different results when unloaded
How Determine Impairment?
Input: Determine FBHP due to Liquids

- Casing/Tubing Differential (if no production packer)
- Run a flowing or static downhole pressure gauge
- Shoot a fluid level with an Echometer™
- Estimate using a model (Prosper, ProdOp)
- Similar wells with fluid level data

You should take multiple observations. The greater the investment, the more you should confirm.
Casing/Tubing Differential

Normal Impaired

Low FBHP
600 PSI

300 PSI
350 PSI

Impaired

High FBHP
900 PSI

300 PSI
600 PSI

Easy Surface Observation
How Determine Impairment?
Output: Determine Well’s Response

• Production trend
• Offset wells of similar completion and depletion
• Testing (foamer, swabbing, etc.)
• Modeling (requires a lot of assumptions)

This is the most difficult part to determine. Normally, you can’t determine with precision, only estimate. Use more than one method to determine order-of-magnitude.
Effects of Loading on Production Decline

Normal Decline

Loading

This is the most common method used to determine the potential rate increase.
Determine Well’s Response

Typical IPR Curve for a Gas Well

Often, the area of interest is pretty close to a straight line. So, a shortcut that is useful is to estimate the $\Delta \text{MSCFD}/\Delta \text{psi}$

IPR curve shows reservoir response to change in flowing bottom hole pressure
Determine Well’s Response
Lower the Flowing Pressure = Increased Rate!

Flowing Pressure, psia

Rate, mscfd

Loaded – High FBHP

Unloaded – Low FBHP

Rate, mscfd
Effects of Artificial Lift on Production Decline

Rate, MCFD

Normal Decline

What if installed here?

Goal of Artificial Lift

Loading

Time
How Impaired is the Well? Review

Depends on:

• Height of liquid accumulated $\gg$ BHP

• “Productivity Index” $\Delta$MSCFD/ $\Delta$psi
Break!

Will announce clock time to restart.
Objectives of Today

At the end of this course, you will understand:

- Is my well impaired?
- How impaired is it?
- What can I do about it?
A Step Back.. 3 Physical Methods

- Eliminate the liquid phase downhole
- Blow liquid in droplet form to the surface with the “wind”
- Separate liquid and move it to the surface in a tube
Selecting a Deliquification Method
Back to Business…

Eliminate Liquid:
Rarely possible

Use Well’s Energy:
Usually lower cost/pain

Add Energy:
Usually higher cost/pain

Lots of factors to balance:
How low of a FBHP can be achieved
Mechanical limitations
Initial cost
Operating cost
Reliability
Personnel availability …

No single solution can take a well from first completion to abandonment
Selecting a Deliquification Method
Wellbore Integrity, Regulations, Size

• Legal or policy requirements for placement of downhole equipment
  – Must be able to prove ongoing wellbore integrity.
  – Must have safety valve in flow path.

• Wellbore Sizes
  – Production Casing: ≤ 5-1/2” vs. 9-5/8”+
  – Tubing: 2-3/8” vs. 5-1/2”+

• Higher flowrates
Option 1: Eliminate Liquid

- Keep liquid from condensing
  - Only if liquids aren’t present at perfs
  - Heat wellbore and/or insulate
- Separate downhole and pump into disposal zone
  - Have to have disposal zone; better if below.
  - Usually works if only water (oil is valuable).

Neither has wide application, but are elegant solutions when possible.
Option 2: Use the Well’s Energy

- **Venting** (kick off only)
- **Equalizing** (kick off only)
- **Cycling**
- **Velocity (Siphon) Tubing Strings**
- **Foamer**
- **Plunger Lift**
**Venting (Kick-off Only)**

**Basic Concept**

Lower surface pressure to atmospheric to increase gas velocity

“Blows” liquid out of the wellbore
Pros
• Operator can do it without any other resources
• Can use in combination with other remedies (foamer, equalizing, etc.)
• Can be automated, but this raises safety concerns

Cons
• If not provided for:
  − can cause a liquids spill
  − can result in a flammable atmosphere
• Blowing source of revenue into the air
• Reporting of Vented Volumes is Law, not optional
• Wastes energy that could be utilized more efficiently, liquid fallback
Equalizing (Kick off only)

Basic Concept

• Shut well in until pressures stabilize
• Forces most liquid back into formation
• Open well to flow
Pros
• Operator can do it without any other resources.
• Does not vent gas.

Cons
• It isn’t a solution for a well that is routinely loading up.
Cycling (Intermitting, Stop Clocking)

Basic Concept

- Shut in well and allow casing pressure to build up
- Open well to flow to displace liquids
- Continue to flow well until well begins loading again
- Repeat cycle
Cycling Summary

Pros

• Low initial cost
• Capable of being automated
• Can use in combination with other remedies (equalize, venting, etc.)
• Initial settings can be found with the help of 2 pen pressure recorder

Cons

• Wastes energy that could be utilized more efficiently, liquid fallback
• Unless automated, can't adjust with changing conditions requiring operator time to optimize
• Cannot reach maximum production without mechanical interface
• Works for a limited amount of time and then must be replaced
• Can't reach low bottom hole pressures (remember IPR curve)
Velocity (Siphon) Strings

**Basic Concept**
Run smaller diameter string to increase gas velocity
Velocity String Example 1
Coiled Tubing – Wyoming, USA

Total Cost: $20,121

- 7” Casing
- 2-3/8” Tubing
- 1-1/4” CT

CT Velocity String Installed

Average rate for 90 days prior to installation: 246 mcfd
Average for last 30 days: 327 mcfd

Paid out in 3 months

MCFD
Tubing PSI
Casing PSI
Line PSI
Projection
Velocity String Example 2
Coiled Tubing – Wyoming, USA

Gross Cost: $19905

Average rate for 90 days prior to installation: 911 mcfd
Average rate for last 30 days: 539 mcfd

5-1/2” Casing  2-3/8” Tubing  1-1/4” CT

CT Installed

Average for 90 days prior to installation: 911 mcfd
Average for last 30 days: 539 mcfd
J Curves for Velocity Strings

Today
Future

This part gives higher BHP due to liquids accumulation...

..while this part of the J-Curve is due to friction.

Which tubing size would you choose?
Height of Fluid
1 BBL can be 100ft or 2200ft
Height of Fluid Affects Hydrostatic Pressure

2 3/8" pipe & 1 bbl of water = 250ft (76m)
Hydrostatic Pressure = 250 ft x .433 (gradient of water) = 108 psi (7.4 bar)

1 1/4" pipe & 1 bbl of water = 640ft (195m)
Hydrostatic Pressure = 640 ft x .433 = 277 psi (19 bar)

1 1/4" pipe & 0.39 bbl of water = 250ft (76m)
Hydrostatic Pressure = 250 ft x .433 = 108 psi (7.4 bar)
Velocity Strings

Summary

Pros

• Smaller tubing = lower flow rate required to keep it unloaded
• No maintenance, steady flow
• Can flow up backside when rate restricted
• Can be selected with future plunger or pump in mind

Cons

• **Installed too early can actually choke a well**
  - A way to overcome this is “tubing flow control”
• Will not produce well to abandonment by itself!
• Once loaded up, the smaller the tubing, the harder to unload
  - Due to hydrostatic pressure & surface area for bottomhole pressure
• While it is possible to plunger lift, it is more difficult
  - Relates again to hydrostatic pressure & surface area. Less room for error
• Costly to change out
Foamer (Soaping)

**Basic Concept**
- Reduces *surface tension and density* of the produced water.
- Reduces the *required gas velocity* needed to lift water.

**Application Methods:**
- **Soap Sticks** – short term impact & good test
- **Batch Treatments** – short term impact & good test
- **Continuous Backside Injection**
  - Needs Packer-less completion
  - Only effective to the end of the production tubing
- **Capillary Injection** – Continuous Pin-Point Injection

*Less effective if have condensates*
Foamer Example 1
Coiled Tubing

3-1/2” Casing  1-1/4” CT

CT Installed
Soap Injection

Gas Rate (MCF/D)

Graph showing gas rate (MCF/D) over time, with markers for CT installed and soap injection.

Example 1
Coiled Tubing
Foamer Example 2
Downhole Video Experiment

- Producing ~350 MSCFD
- Casing pressure was 30 psig (2 bar) over tubing pressure.
- ProdOp J-curve modeling suggested tubing did not have liquid level before treatment.
- The well was shut-in ~36 hours before the batch soap treatment.
Foamer Example 2
J-Curve Analysis

**Liquid Loading J-Curve with Gray (Mod)**

This part gives higher BHP due to liquids accumulation...

- **Pfwh**: 55 psig
- **Condensate**: .0 bbl/MMscf
- **Water**: 2.0 bbl/MMscf
- **Tubing String 1**

**Production**

- **Flowing BHP (psig)**
  - 540
  - 490
  - 440
  - 390
  - 340
  - 290
  - 240
  - 190
  - 140

- **Gas Rate (Mscfd)**
  - 100
  - 200
  - 300
  - 400
  - 500
  - 600
  - 700
  - 800
  - 900
  - 1000
  - 1100
  - 1200
  - 1300
  - 1400
  - 1500
  - 1600
Foamer Example 2
Post-Video

Well making about 350 MSCFD;
Shut-in for batch treatment;
Returned to 390 MSCFD (~10% increase) at comparable casing pressure.
Foamer Example 2
Video Conclusions

- Water foams in slugs, not a continuous foam column
- Liquid level was below top perf when batching began. Foam bullets can be seen coming from the casing.
- Friction
  - Foam Friction Pressure up the tubing was significant
    - Casing Pressure: 80 psi (5.5 bar) vs. normal of 30 psi (2 bar) for about 24 hours
    - Well stabilized at 30 psi (2 bar) friction & at a higher rate of 390 Mscfd
- Water collects in couplings = Corrosion Mechanism
- Conclusions
  - Liquid in the casing covering perfs from 6910 - 6920 ft (2106 – 2109 m) was what was cleared from the well, and this added ~10% production.
  - Alternately, liquid level was higher during previous production period, & was pushed back into the formation during the Shut-in period, & then cleared out by the soap.
**Soap Fall Rate**

- **3,700 ft / hr** (Video) vs. **2,000 ft / hr** (Previous Rule of Thumb for automated controls)
- Opportunity to Reduce Shut-in Times = More Flow-time

**Decreased Shut-in Time = Reduced Casing Pressure by 20%**

- SI time ↓ 350 to 120 min
- SI Time ↑ 120 to 220 min

![Graph showing SI time and pressure changes]
Foam Assisted Critical Flow Rates

Foamer Reduces Critical Velocity By:
- Altering the Properties of the Produced Water
- Reducing Surface Tension
- Reducing Density
Gas Well Applications

- Chemical Foamer Delivery System
- Foamer Reduces Water Surface Tension/Density
- 50% to 66% Reduction in Critical Velocity
- Surface Control Rate of Injection
- Combination Chemical Options – Foamer/Inhibitors

Gas Well Challenges

- Oil / Water Cuts
- Soap Injection Volume
- Capillary Injection String Plugging
- Metallurgy Selection
## Capillary Injection Considerations

<table>
<thead>
<tr>
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<th>Typical Range</th>
<th>Maximum</th>
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<tbody>
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<td>8,000 - 12,000’ TVD</td>
<td>22,000’ TVD</td>
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<tr>
<td>Operating volume</td>
<td>10-50 BFPD</td>
<td>&gt;200 BFPD</td>
</tr>
<tr>
<td>Operating temperature</td>
<td>250° F</td>
<td>400° F</td>
</tr>
<tr>
<td>Wellbore deviation</td>
<td>&lt;5°</td>
<td>60°</td>
</tr>
<tr>
<td>Corrosion handling</td>
<td>Excellent</td>
<td></td>
</tr>
<tr>
<td>Gas handling</td>
<td>Excellent</td>
<td></td>
</tr>
<tr>
<td>Solids handling</td>
<td>Fair to Moderate</td>
<td></td>
</tr>
<tr>
<td>GLR required</td>
<td>300 SCF/BBL/1000’ depth</td>
<td></td>
</tr>
<tr>
<td>Servicing</td>
<td>Requires Capillary Unit</td>
<td></td>
</tr>
<tr>
<td>Prime mover type</td>
<td>Well’s natural energy</td>
<td></td>
</tr>
<tr>
<td>Offshore application</td>
<td>In Development</td>
<td></td>
</tr>
<tr>
<td>System efficiency</td>
<td>N/A</td>
<td></td>
</tr>
</tbody>
</table>
What if have a SSSV?
There are options available

Major Components
1) Injection line into wellhead tree
2) Insert Adaptor System
**Condition Based Soap Injection**

**Treatment Cycle**

- Well falls outside of set conditions
- Well shut-in by automation
- Pre-set amount of surfactant is injected
  - Down tubing, annulus or capillary string
- Well stays shut-in
  - Soap falls and percolates through the water.
- Well is returned to production
  - Allows foamer to mix and bring the water to surface.

*multi-chem® has built a skid for offshore applications similar to this method (multi-skid)*
Foamer Summary

**Pros**
- Helps minimize venting
- Capable of being automated or truck treated
- Useful in wells not capable of using other remedies (e.g. offshore)

**Cons**
- Cost, especially if automated or truck treated. Ongoing.
- Some water must be present to make this work. Soap does not dissolve in oil or drip. Bottle tests can be run to verify.
- Can plug tubing, particularly when no water is present
- Soap is a scale enhancer
- Valuable operator time is used
- When automated, can't adjust with changing conditions
- Safety: chemical handling, PPE, electrical equipment safety
Plunger Lift

Basic Concept

• Similar to cycling
• Mechanical plunger (vertical pig) in tubing to reduce liquid fallback and increase efficiency
Plunger Lift Example
Plunger Lift System Overview

Gas Well Applications
- Usually Your First Choice
- Lowest Cost Solution
- Uses Well’s Own Energy to Lift Liquids
- Specifically Designed for Dewatering Gas Wells

Gas Well Challenges
- Velocities – High or Low
- Gas Liquid Ratios – Must Have Gas….
- Optimization / Maintenance
Plunger Types And Equipment

**RapidFlo Plungers**
- Spiral
- Brush
- Padded
- RapidFlo

- No or Reduced Off Time
- Fall Through Flow
- Higher Gas Velocities Needed

**Conventional Plungers**
- Pad x Pad
- Spiral
- Brush

- Minimum Off Time Required Based on Depth
- Can Not Fall Through Flow
- Differential Pressure Required

**Bumper Springs**

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Variety of Plungers
Plunger Lift Controllers

Controller Options:
- Pressure and Flow Activated
- Time Cycle
- Self Adjusting
- Telemetry Available
Progressive Plunger System

- Used in Lower GLR Gas Wells
- Intermediate Landing Assembly
- Set at +/- 60% of Tubing Depth
- Progressively Transfers Fluid
- Can Install More than One in a Well
- Used in Mixed Strings of Tubing

- Currently Installing Two Intermediate Landing Assemblies in a 17,000’ Well in Western Oklahoma
Safety Lift System

Plunger Lift Below Safety Valve
Plunger Lift
Summary

Pros
• Low Cost to purchase, install, and move
• Low Maintenance (Shock Spring and Plunger)
• Can be automated to adjust for changing well conditions
• Works well in standard to large tubing strings
• With adequate GLR and pressure (400 SCF/BBL/1000ft) can lift high liquid rates.
• Companies are working on solutions for wells with SSSV’s

Cons
• Under wrong conditions, the plunger is a projectile and can blow off the top of the tree.
• Requires more analytical capabilities of the operator so it requires more time and attention.
• Stalls out at low bottom hole pressure
• Hard to operate in small tubing and with sand
Option 3: Add Energy to the Well

• **Downhole Pumps**
  – Rod Pumps (aka Beam Lift, aka plunger pump)
  – ESP: Electric Submersible Pump
  – PCP: Progressive Cavity Pump
  – Others

• **Gas Lift**

• **Compression**
Downhole Pumps

Four Elements in Well:
- Downhole Separator
- Line to Transfer Energy
- Pump/Motor
- Tube to Carry Liquid Up
Pros
- Capable of achieving the **Absolute Minimum FBHP**
- Can be used up to Plug and Abandonment
- Can be automated with pump off controllers to make changes as well conditions change

Cons
- **High cost** to purchase, install, and maintain
- **High maintenance**
  - Rod parts, pump changes, tubing wear, grease, oil, engine, mtr, etc.
  - Can purchase many options with the cost of one pump change.
- **Prime Movers**
  - Gas Engines – high maintenance, difficult to control
  - Electric motors, monthly operating expense IF you are lucky
- **Gas locking worse than normal in high GLR wells**
- **Safety** – more moving parts, more opportunity for error.
Gas Lift

Basic Concept

• Inject gas into flow stream to increase gas velocity in tubing above critical

• Can also inject via CT inside production tubing
Gas Lift Summary

Pros

• Low cost if high pressure gas source available
• Low maintenance on well components
• Better for high GLR wells
• Handles sand nicely

Cons

• High cost and maintenance if you have to get a compressor
• Need startup gas supply, may be expensive if not already available
• Does not give low FBHP compared to pumping
• Key tradeoff: More gas lift valves, less expensive compressor
  - No valves is called “poor boy gas lift”
  - Lots of valves means the facilities engineer got involved.
Compression

Basic Concept
Lower surface pressure below line pressure to increase gas velocity and unload liquids
Compression

Pros

• Increases rate by lowering suction (line) pressure and unloads
• Very attractive in when small changes in pressure give big changes in rate
• Compressors can be rented and maintained by the vendor.
• Can be used on wells with mechanical limitations
• Can be used with plungers, stop clocks, and recirc.

Cons

• Won’t kick off a well. Often a short term fix and a downhole solution is later required.
• Purchase/rental and operating costs; high maintenance
• Safety - Fire hazards, moving parts
How do you choose a method?

- Many different approaches:....

Weatherford Unloading Selector Tool
Weatherford Unloading Selector Tool
What Factors Can WE Control on a Gas Well?

- Flow Areas
- Properties of the Produced Fluid
- Mechanical Interface Between Liquids and Gas
  - Plunger Lift or “Energy In” Solutions
- Line Pressure

Creative Manipulation required to reach our goals

........MORE GAS......
The amount of data required for a full evaluation can be overwhelming or not available at all....
### GLR (SCF/STB) vs BLPD

<table>
<thead>
<tr>
<th>GLR (SCF/STB)</th>
<th>500</th>
<th>1,000</th>
<th>5,000</th>
<th>10,000</th>
<th>50,000</th>
<th>100,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.5</td>
<td>1</td>
<td>5</td>
<td>10</td>
<td>50</td>
<td>100</td>
</tr>
<tr>
<td>10</td>
<td>5</td>
<td>10</td>
<td>50</td>
<td>100</td>
<td>500</td>
<td>1,000</td>
</tr>
<tr>
<td>100</td>
<td>50</td>
<td>100</td>
<td>500</td>
<td>1,000</td>
<td>5,000</td>
<td>10,000</td>
</tr>
<tr>
<td>1,000</td>
<td>500</td>
<td>1,000</td>
<td>5,000</td>
<td>10,000</td>
<td>50,000</td>
<td>100,000</td>
</tr>
</tbody>
</table>

**GAS RATE MCFD**

### Well Classifications

- **Liquid Wells**
- **Wet Gas Wells**
- **Gas Wells**

### Variables

<table>
<thead>
<tr>
<th>Variable</th>
<th>Low Value</th>
<th>High Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid Rate</td>
<td>&lt;100 bpd</td>
<td>&gt;100 bpd</td>
</tr>
<tr>
<td>Ftp</td>
<td>&lt;300 psi</td>
<td>&gt;300 psi</td>
</tr>
<tr>
<td>Water Cut</td>
<td>&lt;50%</td>
<td>&gt;50%</td>
</tr>
<tr>
<td>GLR</td>
<td>&lt;10,000 mcf/stb</td>
<td>&gt;10,000 mcf/stb</td>
</tr>
</tbody>
</table>

---

**4 Surface Gathered Pieces Of Data**

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Example Well #1

Pre-Loaded Test Data

- Liquid Rate = 7 bpd
- Ftp = 75 psi
- Water Cut = 60%
- GLR = 42,857 : 1 scf/stb
Example Well #1 Selection Process

Variables:
- Liquid Rate = 7 bpd  LOW
- Ftp = 75 psi  LOW
- Water Cut = 60%  HIGH
- GLR = 42857:1 scf/stb  HIGH
Example Well #1 Real Results

- Jensen #23
- Rusk County, TX
- Perfs: 8,700' - 8,812'

Graph showing data with labels:
- MCFD
- LINE P
- FTP
- BCPD
- BWPD
- CHOKE

Key events:
- RapidFlo Spiral Plunger Installed
- RapidFlo Padded Plunger Installed
- Conventional Plunger Installed
## Example Well # 2

<table>
<thead>
<tr>
<th>Variable</th>
<th>Low Value</th>
<th>High Value</th>
<th>Well # 1 Data</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid Rate</td>
<td>&lt;100 bpd</td>
<td>&gt;100 bpd</td>
<td>257 bbls/d</td>
<td>HIGH</td>
</tr>
<tr>
<td>Ftp</td>
<td>&lt;300 psi</td>
<td>&gt;300 psi</td>
<td>130 psi</td>
<td>LOW</td>
</tr>
<tr>
<td>Water Cut</td>
<td>&lt;50%</td>
<td>&gt;50%</td>
<td>96 %</td>
<td>HIGH</td>
</tr>
<tr>
<td>GLR</td>
<td>&lt;10,000 mcf/stb</td>
<td>&gt;10,000 mcf/stb</td>
<td>.9</td>
<td>LOW</td>
</tr>
</tbody>
</table>
Example Well # 2

Possible Solution=
Positive Displacement Lift System

Is This The Right Answer?

1. HIGH Liquid
2. LOW FTP
3. HIGH H2O
4. LOW GLR
### WELL DATA

<table>
<thead>
<tr>
<th>Measurement Type:</th>
<th>API/English</th>
<th>Metric</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vertical</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Directional</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Slant</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deviation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Build Angle/degree</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(include directional survey-measured depth, hole angle, azimuth)

<table>
<thead>
<tr>
<th>Casing Data:</th>
<th>Size</th>
<th>Weight</th>
<th>Depth</th>
<th>Perforations:</th>
<th>From</th>
<th>To</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>5.5</td>
<td>17</td>
<td>9253</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Casing Liner:</th>
<th>Size</th>
<th>Weight</th>
<th>Depth</th>
<th>Perforations:</th>
<th>From</th>
<th>To</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Open Hole:</th>
<th>Diameter</th>
<th>Depth</th>
<th>Desired or Existing Pump Depth</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Tubing Data:</th>
<th>Size</th>
<th>Weight</th>
<th>TVD</th>
<th>Length</th>
<th>Anchored</th>
<th>Seating Nipple: Depth</th>
<th>Size</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2.38&quot;</td>
<td>4.7#</td>
<td>7390</td>
<td>7420</td>
<td>Y</td>
<td>7390</td>
<td>X</td>
<td>1.875&quot;</td>
</tr>
</tbody>
</table>

Advising other special conditions (i.e. water flood, height or noise limitations): Visually Sensitive Area/Must Have Low Profile Solution/Quiet

---

### PRODUCTION & FLUID DATA

Data will be entered using the following measurement type: API/English |**X**| Metric | Other | (If other enter type) |

<table>
<thead>
<tr>
<th>Specific Gravity:</th>
<th>Oil</th>
<th>API°</th>
<th>Water Cut</th>
<th>Water</th>
<th>Gas</th>
<th>S.G.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>52</td>
<td></td>
<td>96%</td>
<td>1.13</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>GOR</th>
<th>%</th>
<th>GLR 972:1 or .9</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Bubble Point Pressure:</th>
<th>Total Fluid Viscosity</th>
<th>Centipoise</th>
<th>Bottomhole Temperature</th>
<th>219</th>
<th>Deg.</th>
<th>F</th>
<th>X</th>
<th>C</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Water Salinity (ppm)</th>
<th>Fluid pH</th>
<th>Chlorides (ppm)</th>
<th>Paraffin</th>
<th>H₂S</th>
<th>%</th>
<th>CO₂</th>
<th>%</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Abrasives:</th>
<th>Sand:</th>
<th>Light</th>
<th>Mod.</th>
<th>Heavy</th>
<th>Scale:</th>
<th>Light</th>
<th>Mod.</th>
<th>Heavy</th>
<th>Iron</th>
<th>Sulfides:</th>
<th>Light</th>
<th>Mod.</th>
<th>Heavy</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Pressures:</th>
<th>Static BHP</th>
<th>At Depth</th>
<th>Flowing BHP</th>
<th>Casing</th>
<th>Tubing</th>
<th>Flowline</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4100</td>
<td>8500</td>
<td></td>
<td>950</td>
<td>150</td>
<td>130</td>
</tr>
</tbody>
</table>

Is there a chemical treatment program in place? Y | N | If "Y" who is the chemical vendor? |

---

### DESIRED PRODUCTION RATE

Data will be entered using the following measurement type: API/English |**X**| Metric | Other | (If other enter type) |

<table>
<thead>
<tr>
<th>Well's current type</th>
<th>New</th>
<th>Flowing</th>
<th>Beam</th>
<th>ESP</th>
<th>Hydraulic</th>
<th>Gas</th>
<th>PCP</th>
<th>Plunger</th>
<th>Suspended/Dead</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Prime Mover Type:</th>
<th>Gas</th>
<th>Electric</th>
<th>If electric – Variable Speed Drive</th>
<th>Y</th>
<th>N</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>24 hr. Production Test:</th>
<th>Oil</th>
<th>bbl/day</th>
<th>Water</th>
<th>Gas</th>
<th>Flowing BHP</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>7</td>
<td></td>
<td>250</td>
<td>250</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Date of Test:</th>
<th>Oil</th>
<th>Water</th>
<th>Gas</th>
<th>Flowing BHP</th>
</tr>
</thead>
<tbody>
<tr>
<td>9-16-06</td>
<td>10</td>
<td>350</td>
<td>400</td>
<td></td>
</tr>
</tbody>
</table>

Artificial Lift Systems NOT to be considered (check all that apply): Beam | ESP | Gas | Hyd. Jet | Hyd. Recp. | PCP | Plunger |

Reasons NOT to consider: |
Sample Well # 3

Production Rate below Critical Flow Rate
Significant Liquid Loading Occurs
Sample Well #3

Test Well

- Pre-Loaded Test Data
- Liquid Rate = 10 bpd
- Ftp = 100 psi
- Water Cut = 80%
- GLR = 30,000 scf/stb
Example Well #3 Selection Process

Variables:
- Liquid Rate = 10 bpd
- Ftp = 100 psi
- Water Cut = 80%
- GLR = 30,000 scf/stb
Operator starts Capillary Injection of Combination Foamer, Corrosion Inhibitor. Production Rate Exceeds Critical Flow Rate for Foam System

Why Did Operator Use Cap String Instead of Plunger Lift?

There was a Tubing Restriction at 8,237 ft
The Unloading Selector

Assists in the selection of the most effective and economical lift system for gas-well unloading—from Weatherford, the world leader in artificial lift.

How do I know whether my gas wells need unloading?

Recovering the early signs of gas-well fail loading and properly selecting the right lift system can solve the problem before production loss and possible formation damage occurs. The three most common symptoms of liquid loading are:

- Pressure differential between tubing and casing in producing completion
- Liquid slugging and/or reduced gas production
- Viscosity from precipitated production-decline curve

The Unloading Selector uses four primary production parameters to select the most effective and economical lift solution for your gas-well unloading needs.

How do I use the Unloading Selector?

Start at the center of the wheel and work outward. Find the appropriate lift system based on your gas/water ratio, flowing bottomhole pressure, and monthly gas production. The segments of the outer rim describe the most suitable lift system needed for your application.

Select the lift system that best matches your well's characteristics and proceed to the next parameter.

Weatherford

Get more help from The Unloading Expert:

To learn more about Weatherford's range of gas-well unloading equipment, contact your local Weatherford representative, or visit weatherford.com/Unloading.
Deliquification Final Thoughts…..

- Daily production from your well, does not mean that the well is “flowing” or “unloaded”…..
  - Field Automation is a major technical advance. But you can miss the REST OF THE STORY……
  - Daily Automation Gas Rate = 200mcf/d….Is that all it can make?

- Gas wells do not get stronger over time…………

- Proactive Solutions
### ALS Application Screening Criteria

<table>
<thead>
<tr>
<th>Form of lift</th>
<th>Rod Lift</th>
<th>PCP</th>
<th>Gas Lift</th>
<th>Plunger Lift</th>
<th>Hydraulic Lift</th>
<th>Hydraulic Jet</th>
<th>ESP</th>
<th>Capillary Technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum operating depth, TVD (ft/m)</strong></td>
<td>16,000 4,878</td>
<td>12,000 3,658</td>
<td>18,000 4,572</td>
<td>19,000 5,791</td>
<td>17,000 5,182</td>
<td>15,000 4,572</td>
<td>15,000 4,572</td>
<td>22,000 6,705</td>
</tr>
<tr>
<td><strong>Maximum operating volume (BFPD)</strong></td>
<td>6,000</td>
<td>4,500</td>
<td>50,000</td>
<td>200</td>
<td>8,000</td>
<td>20,000</td>
<td>60,000</td>
<td>500</td>
</tr>
<tr>
<td><strong>Maximum operating temperature (°F/°C)</strong></td>
<td>550°/288°</td>
<td>250°/121°</td>
<td>450°/232°</td>
<td>550°/288°</td>
<td>550°/288°</td>
<td>550°/288°</td>
<td>400°/204°</td>
<td>400°/204°</td>
</tr>
<tr>
<td><strong>Corrosion handling</strong></td>
<td>Good to excellent</td>
<td>Fair</td>
<td>Good to excellent</td>
<td>Excellent</td>
<td>Good</td>
<td>Excellent</td>
<td>Good</td>
<td>Excellent</td>
</tr>
<tr>
<td><strong>Gas handling</strong></td>
<td>Fair to good</td>
<td>Good</td>
<td>Excellent</td>
<td>Excellent</td>
<td>Fair</td>
<td>Good</td>
<td>Fair</td>
<td>Excellent</td>
</tr>
<tr>
<td><strong>Solids handling</strong></td>
<td>Fair to good</td>
<td>Excellent</td>
<td>Good</td>
<td>Fair</td>
<td>Fair</td>
<td>Good</td>
<td>Fair</td>
<td>Good</td>
</tr>
<tr>
<td><strong>Fluid gravity (°API)</strong></td>
<td>&gt;8°</td>
<td>&lt;40°</td>
<td>&gt;15°</td>
<td>&gt;15°</td>
<td>&gt;8°</td>
<td>&gt;8°</td>
<td>&gt;10°</td>
<td>&gt;8°</td>
</tr>
<tr>
<td><strong>Servicing</strong></td>
<td>Workover or pulling rig</td>
<td>Wireline or workover rig</td>
<td>Wellhead catcher or wireline</td>
<td>Hydraulic or wireline</td>
<td>Workover or pulling rig</td>
<td>Capillary unit</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Prime mover</strong></td>
<td>Gas or electric</td>
<td>Gas or electric</td>
<td>Compressor</td>
<td>Well's natural energy</td>
<td>Multicylinder or electric</td>
<td>Multicylinder or electric</td>
<td>Electric motor</td>
<td>Well's natural energy</td>
</tr>
<tr>
<td><strong>Offshore application</strong></td>
<td>Limited</td>
<td>Limited</td>
<td>Excellent</td>
<td>N/A</td>
<td>Good</td>
<td>Excellent</td>
<td>Excellent</td>
<td>Good</td>
</tr>
<tr>
<td><strong>System efficiency</strong></td>
<td>45% to 60%</td>
<td>50% to 75%</td>
<td>10% to 30%</td>
<td>N/A</td>
<td>45% to 55%</td>
<td>10% to 30%</td>
<td>35% to 60%</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Values represent typical characteristics and ranges for each form of artificial lift. Parameters will vary according to well situations and requirements and must be evaluated on a well-by-well basis.
### Efficiency Comparison (versus other ALS)

<table>
<thead>
<tr>
<th>Energy Efficiency:</th>
<th>Most Typical Range</th>
<th>Overall Range</th>
<th>Reasons for Inefficiencies:</th>
</tr>
</thead>
<tbody>
<tr>
<td>PCP</td>
<td>![PCP Chart]</td>
<td></td>
<td>Slippage through the pump; friction effect in pump; losses in energy transmission from surface to pump; internal losses of the surface drive system; handling of multiphase fluids</td>
</tr>
<tr>
<td>Rod</td>
<td>![Rod Chart]</td>
<td></td>
<td>Slippage through the pump; losses in energy transmission from surface to pump; extra-energy utilized to overcome peaks in upstrokes; handling of multiphase fluids</td>
</tr>
<tr>
<td>ESP</td>
<td>![ESP Chart]</td>
<td></td>
<td>Dynamic pump with maximum mechanic efficiencies not greater than 80% (60% if radial configuration); Electrical losses in bottomhole motor and power cable; equipment itself consume about 30% of the energy; handling of multiphase fluids</td>
</tr>
<tr>
<td>Recipr. Hyd</td>
<td>![Recipr. Hyd Chart]</td>
<td></td>
<td>Considerable amount of energy utilized to handle power fluid; slippage through the pump; energy losses associated to surface equipment; handling of multiphase fluids</td>
</tr>
<tr>
<td>Jet Hyd.</td>
<td>![Jet Hyd Chart]</td>
<td></td>
<td>Considerable amount of energy utilized to handle power fluid; internal energy losses in the diffuser of the pump; energy losses associated to surface equipment; handling of multiphase fluids</td>
</tr>
<tr>
<td>GL Cont.</td>
<td>![GL Cont. Chart]</td>
<td></td>
<td>Most of the energy utilized to compress the gas (over 40%); friction losses across pipelines and wellbore annular area; further expansion of gas</td>
</tr>
<tr>
<td>GL Int.</td>
<td>![GL Int. Chart]</td>
<td></td>
<td>Most of the energy utilized to compress the gas (over 40%); friction losses across pipelines and wellbore annular area; further expansion of gas, the non-continuous operation of the system</td>
</tr>
</tbody>
</table>
Artificial Lift Limitation Rate versus Depth

Barrels per Day

Lift Depth (TVD)

- ESP
- Gas Lift
- Hydraulic Jet Pump
## Type of Reservoir Matters

### Recovery Factor as Percentage of OGIP at 30 BBL/MMSCF

<table>
<thead>
<tr>
<th>Case</th>
<th>Natural Flow</th>
<th>Gas Lift</th>
<th>Pump</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tight, Small</strong> (2 md-ft, 2 BCF)</td>
<td>67%</td>
<td>86%</td>
<td>94%</td>
</tr>
<tr>
<td><strong>Medium</strong> (1000 md-ft, 60 BCF)</td>
<td>87%</td>
<td>89%</td>
<td>94%</td>
</tr>
<tr>
<td><strong>Large, Prolific</strong> (1000 md-ft, 60 BCF)</td>
<td>88%</td>
<td>90%</td>
<td>94%</td>
</tr>
</tbody>
</table>

Note: From SPE 110357
What can I do about it?

Review

- Eliminate Liquid
- Use Well’s Energy
- Add Energy

Did not present all options, only the most common.
Now you understand:

✔ Is my well impaired?
✔ How impaired is it?
✔ What can I do about it?
Activity: Unloading Rates for Various Tubing Sizes - Turner

<table>
<thead>
<tr>
<th>Min Critical Velocity Rate, mcf/d</th>
<th>Case A</th>
<th>Case B</th>
<th>Case C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flowing Tubing Pressure</td>
<td>200</td>
<td>620</td>
<td>50</td>
</tr>
<tr>
<td>Critical Velocity Rate</td>
<td>450</td>
<td>620</td>
<td>160</td>
</tr>
<tr>
<td>Tubing Size</td>
<td>2.375</td>
<td>2.016</td>
<td>1.9</td>
</tr>
</tbody>
</table>

Flowing (Tubing) Pressure, PSIA

Tubing Sizes
- 2.375
- 2.016
- 1.90
- 1.66

- Avg Line Pressure
- Avg Tubing Pressure
- Avg Casing Pressure
- Gas Volume
Example: Flowing up 7” Casing

Gas Rate & Pressure are Daily Averages

Questions:
Is my well impaired?
How impaired is it?
What can I do about it?
Example: Flowing up 7” Casing

Questions:
Is my well impaired?
How impaired is it?
What can I do about it?

Gas Rate & Pressure are Daily Averages
Example: Flowing up 7” Casing

Questions:
Is my well impaired?
How impaired is it?
What can I do about it?

Gas Rate & Pressure are Daily Averages
Same Example: Flowing up 7” Casing

Questions:
- Is my well impaired?
- How impaired is it?
- What can I do about it?

Gas Rate & Pressure are Hourly Averages
Same Example: Flowing up 7” Casing

Questions:
Is my well impaired?
How impaired is it?
What can I do about it?

Gas Rate & Pressure are Hourly Averages

Current Volume
Static Pressure
Avg Tubing Pressure
Avg Casing Pressure
Same Example: Flowing up 7” Casing

Questions:
- Is my well impaired?
- How impaired is it?
- What can I do about it?

Gas Rate & Pressure are Hourly Averages
Wrap-Up

Now you understand:

✓ Is my well impaired?
✓ How impaired is it?
✓ What can I do about it?
Is My Well Impaired?

Liquids Impair a Well Below Critical Velocity

Basically, Critical Velocity is how fast rain drops (about 30 ft/s)
How Impaired is the Well?

Depends on:

- Amount of liquid accumulated $>>$ BHP
- “Productivity Index” $\Delta$MSCFD/ $\Delta$psi
What can I do about it?

Eliminate Liquid

• Use Well’s Energy

• Add Energy
Thanks!

Highly Suggested Reading:
Gas Well Deliquification, 2003
By James Lea, Henry Nickens, Michael Wells