Low Pressure Gas Well Deliverability Issues: Common Loading Causes, Diagnostics and Effective Deliquification Practices

George E. King
What Technology Will Drive Deliquification?

Cost, price?

Life Cycle of a Gas Well

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US Mature Well Base (2001)

- 880,000 producing or temporarily abandoned wells
- 320,000 gas wells (many at 5 to 15 mcf/d)
- Vast majority of these wells are low pressure and low rate.
Gas Wells: Two Facts

• Potential: Very long life in some cases – 30 to over 70 years and large recovery for every extra 10 psi drawdown.

• Challenge: Liquid loading from condensed or connate fluids will kill or sharply reduce the production.
Example: Oklahoma Gas Wells

Oklahoma Gas Production Per Well

Average Flow Per Well

Gas Production Per Well mcf/d

32,672 producing gas wells in 2001
Tubing Performance - Vertical

Oil Well

- Gas, oil, and water
- Oil

Gas Well

- Water vapor condenses as gas rises and expands.
- Water must be removed to allow the well to flow.
- Water that builds up holds a backpressure on the formation.

Gas and liquid

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Turner Unloading Rate, Water

For pressures > 1000 psi

Source – J. Lea, Texas Tech, Turner Correlations.
Minimum Critical Velocities

- Turner and Coleman Equations
- Estimate minimum gas flow velocity needed to lift water droplets out of well.
- If flow velocity below critical, then water droplets fall / build up in bottom of well.
- The well may or may not cease to flow but production will be decreased.
Small Gas Well Example – Lift Progression – 2-3/8” Tubing

Flow and Lift - 2-3/8” Tubing

Source - Bryan Dotson
www.GEKEngineering.com
We’ll have to put energy into the well:

Pump Power
(assumes 50% Efficiency and 200 psid friction drop)

Pump HP

BPD of Water

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How Much Can We Pay?

If plungers get us to 50 MSCFD, we can’t afford too much.
System Requirements

- Low initial cost.
- Reasonable life: 3-5 years; more is better.
- Low cost energy.
- Handle gas gracefully.
- Automatic pump-off control.
- 180F to 280F, to 12000 feet.
- Handle solids and paraffin well.
- Resistant to CO2 and H2S corrosion.
- Works in highly deviated wells.
- Acid-resistant.
- Resistant to scale formation.
The design of the well bore can alter the velocity.

Where is critical rate calculated?

Multiple velocity calculations are needed with gas in compressed state.
Gas Bubble Growth With Rise In A Water Column

Gas column is different – gas is low density at the top of a column and higher density at bottom – so although rate is constant, velocity is not.
Liquids in Gas Wells

• Gas phase – condensing to a liquid
  – Water – several bbls/mmcf, unusually fresh
  – Condensate – can be much higher volume

• Connate Water
  – Usually saltier than condensing water
  – Often stays in bottom of the well.
Where is Critical Rate Calculated? Surface or Bottom Hole?

**Wellhead**
- Pres: 400#
- Temp: 60 deg F
- Tbg: 1 ¼” CT
- Rate: 200 mscfd
- Critical Rate: 180 mscfd

10,000’ 1 ¼” CT

**Bottom of Tubing**
- Pres: 900#
- Temp: 200 deg F
- Critical Rate: 220 mscfd

10,500’ 3 ½” Csg to Perfs

**Casing**
- Pres: 1100#
- Temp: 200 deg F
- Critical Rate: 1500 mscfd

DON’T CALCULATE CRITICAL RATE AT SURFACE ONLY!!!
How much potential water condensation are we facing?
Condensation Drivers

• Loss of temperature
  – Gas condenses to liquid phase

• Loss of Rate
  – Slower velocity =>
    • Poorer lift potential.
    • Longer transit times, more heat loss, more condensation opportunity.
  – Less flowing mass => less total heat to loose before water starts to condense.
Diagnostics: The production history of a well starting to load up. There are usually many causes that lead to load-up.
The liquid holdup applies a backpressure to the bottom hole. Rate is decreased

Enough liquid finally drops down the well to reduce or balance formation pressure. Flow is decreased or the well is dead.

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An increase in the differential between casing and tubing pressure over time indicates loading.

No packer example.
Gradient survey to locate static liquid level.
Lift Selection Considerations

- Size of the prize?
- Cost of water prod?
- How much water?
- Source?
  - Water control?
- Condensation cause?
- Condense location?
- Well limits?
- Safety valve?
- Power?
- Computer control?
- Well W/O costs?
- Well W/O risks?
Lift and Deliquification

- Natural Flow
- Intermitter
- Rocking
- Equalizing
- Venting
- Soaping
- Velocity String
- Compression

- Gas Lift
- Beam Lift
- Plunger
- ESP and HSP
- PCP
- Diaphragm Pump
- Jet Pump
- Eductor
What causes the short-lived increases in rate when a well is started up after a brief shut-in?

What causes the sharp initial decline when the well is brought on?

Can it be used for advantage?
Why the increase after a shut-in?

1. Recharging of the near wellbore from the formation away from the wellbore.

2. Cross flow from low permeability, higher pressure zones to high permeability, partly depleted zones (also recharging).
   - High perm streaks
   - Natural fractures
   - Stimulated fractures
Most formations are layered and often have distinctly different permeabilities in a package of pay.

These layers flow as individual units, emptying the higher perm units first before the lower perm reservoirs begin to flow.

When a well is shut in, higher remaining pressures in the low perm layers cause flow into the high perm, more depleted streaks.

Natural cross flow!
Using Cross Flow

• Repressuring the higher permeability streaks during a shut-in can lend a sharp, short lived increase to flow and can help unload a well without outside equipment or services.

• To use it effectively, the behavior of the well such as how quickly it recharges, how quickly it blows down and what happens to the water during a shut-in must be understood.
Lift and Unloading Options

• At least 15 options of full time and part time lift.
• The well design, conditions and economics dictate the optimum method – and remember – both can change with decline.
• Another very important contributor is the operator.
Well With A Plunger Installation

Installed Plunger
Effective CT Velocity String – Champlin 149-B2

Total Cost: $20,121

MCFD
Tubing PSI
Casing PSI
Line PSI
Projection

Paid out in 3 months

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

Effctive CT Velocity String
– Champlin 149-B2

7” Casing   2-3/8” Tubing   1-1/4” CT

CT Installed

Paid out in 3 months

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

www.GEKEngineering.com
Ineffective CT Velocity String – Champlin 222-C2

Gross Cost: $19905

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

www.GEKEngineering.com
Soap Injection to Reduce Fluid Column Hydrostatic

CT Installed

Soap Injection

Venting to unload wellbore

CG Road 25-4

3-1/2” Casing

1-1/4” CT

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Conclusions

• Small increases in pressure drop can make large gains in production.
  – Every ft of liquid in a well holds nearly $\frac{1}{2}$ psi in backpressure on the formation.
  – Water invading the pores of the rock during a shut-in can be held on the formation and gas cannot displace it.
  – Water refluxing in a gas well is the largest single source of corrosion.
  – Liquid loaded wells may still produce but are very erratic.
Conclusions

• Tubing size is a legitimate and low cost choice ONLY if GLR will allow the well to be placed in mist flow.
• Lift consideration should include the limits and well as the advantages.
• If Turner or Coleman correlations do not work in your applications, develop your own – Really, it’s OK!
Pressure
Effects of
Liquid
Loading

![Graph showing solubility of water in natural gas vs. pressure and temperature.](www.GEKEngineering.com)
Heating Gas – Downhole View During Gas Flow

6132.8  
197 F  
16:59:27

www.GEKEngineering.com
Heating Gas – Downhole View During Gas Flow
Heating Gas – Downhole View During Gas Flow
Heating Gas – Downhole View During Gas Flow
Unstable Gas Well Flow Behavior, Followed by Loading

www.GEKEngineering.com

Jason Piggot, SPE 2002
Pressure Effects of Liquid Loading

Liquid Loading
Results in 30 PSI
Back-Pressure

www.GEKEngineering.com

Jason Piggot, SPE 2002
Heating Gas – Effects on Production

Temperature, Deg. Fahrenheit
Pressure, psig
Rate, Mcf/Day

www.GEKEngineering.com
Heating Gas – Effects on Temperature Gradient

After Heating

Before Heating

www.GEKEngineering.com
Heating Gas – Downhole View During Gas Flow

1003.4'
181°F
13:23:38
Support Slides

• Lift Methods
• Deviated Wells
• Critical Flow Calculations
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 per minute (100 to 500 cc/min).
## Lift and Unloading Options

<table>
<thead>
<tr>
<th>Method</th>
<th>Description</th>
<th>Pros</th>
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<tbody>
<tr>
<td>Natural Flow</td>
<td>Flow of liquids up the tubing propelled by expanding gas bubbles.</td>
<td>Cheapest and most steady state flow</td>
<td>May not be optimum flow. Higher BHFP than with lift.</td>
</tr>
<tr>
<td>Continuous Gas Lift</td>
<td>Adding gas to the produced fluid to assist upward flow of liquids. 18% efficient.</td>
<td>Cheap. Most widely used lift offshore.</td>
<td>Still has high BHFP. Req. optimization.</td>
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<td>Hydraulic pump</td>
<td>Hydraulic power fluid driven pump. 40% efficient.</td>
<td>Works deeper than beam lift.</td>
<td>Req. power fluid string and larger wellbore.</td>
</tr>
<tr>
<td>Beam Lift</td>
<td>Walking beam and rod string operating a downhole pump. Efficiency just over 50%.</td>
<td>V. Common unit, well understood,</td>
<td>Must separate gas, limited on depth and pump rate.</td>
</tr>
<tr>
<td>Specialty pumps</td>
<td>Diaphram or other style of pump.</td>
<td>Varies with techniques.</td>
<td>New - sharp learning curve.</td>
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<td>Intermittent Gas Lift</td>
<td>Uses gas injected usually at one point to kick well off or unload the well followed by natural flow. 12% efficient.</td>
<td>Cheap and doesn’t use the gas volume of continuous GL.</td>
<td>Does little to reduce FBHP past initial kickoff.</td>
</tr>
<tr>
<td>Jet pump</td>
<td>Uses a power fluid through a jet to lift all fluids</td>
<td>Can lift any GOR fluid.</td>
<td>Req. power fluid string. Probs with solids.</td>
</tr>
<tr>
<td>PCP</td>
<td>Progressive cavity pump.</td>
<td>Can tolerate v. large volumes of solids and ultra high visc. fluids.</td>
<td>Low rate, costly, high power requirements.</td>
</tr>
<tr>
<td>Plunger</td>
<td>A free traveling plunger pushed by gas below to mover a quantity of liquids above the plunger.</td>
<td>Cheap, works on low pressure wells, control by simple methods</td>
<td>Limited volume of water moved, cycles backpressure.</td>
</tr>
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<td>Soap Injection</td>
<td>Forms a foam with gas from formation and water to be lifted.</td>
<td>Does not require downhole mods.</td>
<td>Costly in vol. Low water flow. Condensate is a problem.</td>
</tr>
<tr>
<td>Compression</td>
<td>Mechanical compressor scavenges gas from well, reducing column wt and increasing velocity.</td>
<td>Does not require downhole mods.</td>
<td>Cost for compressor and operation. Limited to low liquid vols.</td>
</tr>
<tr>
<td>Velocity Strings</td>
<td>Inserts smaller string in existing tbg to reduce flow area and boost velocity</td>
<td>Relatively low cost and easy</td>
<td>Higher friction, corrosion and less access.</td>
</tr>
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<td>Cycling / Intermittent</td>
<td>Flow well until loading starts, then shut in until pressures build, then flow.</td>
<td>Cheap. Can be effective if optim. No DH mods.</td>
<td>Req. sufficient pressure and automation (?)</td>
</tr>
<tr>
<td>Equalizing</td>
<td>Shuts in after loading. Building pressure pushes gas into well liquids and liquids into the formation.</td>
<td>Will work if higher perm and pressure. No downhole mods.</td>
<td>Takes long time. May damage formation.</td>
</tr>
<tr>
<td>Rocking</td>
<td>Pressure up annulus with supply gas and then blow tubing pressure down.</td>
<td>Inexpensive and usually successful.</td>
<td>Req. high press supply gas. Well has no packer.</td>
</tr>
<tr>
<td>Venting</td>
<td>Blow down the well to increase velocity and decrease BHFP.</td>
<td>Cheap, simple, no equipment needed.</td>
<td>Not environmentally friendly.</td>
</tr>
</tbody>
</table>

Note that some lift systems are depth limited and some are volume limited. Almost all are limited to some extent by the diameter of the wellbore.
Deviated Wells

• About 30% of US produced gas comes from offshore.
• Most offshore wells are deviated – Flow is very different in deviated wells!
The liquid flow character can change dramatically with depth and deviation.

Severe liquid holdup by reflux motion is common in the Boycott Settling range of 30° to 60°.
In deviated wells, liquid holdup, sometimes seen as a reflux or percolation in sections of the tubing, can account for large volumes of water and significant backpressure on the formation.
Nearly vertical well

- Oil and water (mixed) everywhere across the section of the pipe.
- Smooth velocity profiles.
- Almost linear holdup profiles.
Deviated well

- Very complex flow structure.
- Monophasic water phase at the bottom of the pipe.
- Dispersed oil phase at the uppermost of the pipe.
- Large velocity and holdup gradients.

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