Diagnosing and Solving Plunger Lift Problems

David Green, P.Eng.
Well Master Corporation
What’s Wrong With My well?
Problem Areas

**Mechanical Factors**
- Surface Facilities
- Tubing Placement
- Holes in Tubing
- Tubing Tight Spots

**Plunger Factors**
- Worn Plunger
- Wrong Plunger
- Incorrect Operating Parameters
- Scale, Paraffin, Sand
What Diagnostic Tools Do We Have?

• Eyes and Ears
• Wellhead Controllers
• Flow Measurement Devices
• SCADA Systems
• Acoustic Device
• Instrumented Plunger (Pressure, Temperature, Location)
• Don’t just assume you have a plunger problem first
• Start site inspection from the last point of gas flow and work back to the wellhead
• Check EFM, separator for gas leaks, leaky dump valve
• Check sales valve for full open and close
• Check needle valves and regulators at wellhead
• Check orifice plate correct size at EFM
Plunger Inspection

• Pull plunger to inspect for damage
• Measure solid plunger diameter with micrometer or use gauge ring
• Inspect pad plungers for pad wear and loss of spring tension – use a gauge ring if available
• Insect brush plungers for wear
What Diagnostic Tools Do We Have?

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SCADA

• Often times we can see problems with our SCADA systems
• Typical things to look for:
  – Rising casing pressure trends (loading)
  – Increasing casing – tubing differential pressures (loading)
  – Loss of tubing pressure in closed cycle (leaking sales valve)
  – Rapid equalization of casing and tubing pressures (hole in tubing)
  – Unusual patterns…..usually point to more serious things
Blocked Intake into Tubing

Tbg Pressure Rapid Build

Rapid Tbg Pressure Decline

Casing Pressure at start should have surfaced plunger in 1.89 minutes – instead plunger took 23 minutes to surface.
Some Causes of Blocked Tubing Intake

- Check first to see if there is a packer in the well – this will give a similar pattern
- Salt or scale between casing and tubing
- Scale in tubing at the seat nipple or downhole spring assembly
- Stuck standing valve
- Liquid always above tubing inlet
Small hole Began to Cause Problem
Drop in Production due to Liquid Loading? Shot Fluid Levels to Open Sliding Sleeve and Commingle Two Zones
Found Hole in Tubing With Fluid Level Shot
Dramatic Drop in Rate from 820 Mscfd to 250 Mscfd
Turner Critical 320 MscfD
Replaced Tubing and Gas Flow Returned to 2006 Rate
Holes in Tubing and Corrosion in Flowing Gas Wells are a Common Problem

• Tubing holes often misdiagnosed or over-looked.
• Production rate drops and looks like liquid loading as gas rate falls off
• Casing-tubing pressure gradually equalizes during close cycle (easier to see if SCADA data is available)
• Problems occur gradually as hole size increases
• Plunger begins to slow-trip or miss trips
• Often the plunger is changed when wear is suspected, but results don’t change
Tools to Find Holes in Tubing

1. Acoustic (Echometer)

2. Instrumented Plunger
Can’t be a Hole ~ Tubing is New

Hole @ Depth 4325 Ft from Surface

Inside Pipe

Outside Pipe
1. Well was Liquid Loaded
2. Fluid Level Shots Showed Tubing was OK

Tubing Hole -- Sand Blast Gas Flow From Upper Set of Perforations
Shots Down Tubing & Casing

- Hole in Tubing @ 6868'

**Tubing Shot**
- Tubing Pressure: 228.8 psi (g)
- Tubing Pressure Buildup: 0.036 psi, 1.75 min
- Gas/Liquid Interface Pressure: 268.6 psi (g)
- Liquid Level Depth: MD 6919.46 ft

**Casing Shot**
- Liquid Below Tubing:
  - Oil: 0 %
  - Water: 100 %
  - % Liquid Below Tubing: 99 %
- Tubing Intake Depth:
  - MD 8283.27 ft
  - TVD 8283.27 ft
  - Formation Depth: MD 8299.70 ft

**Well State**
- Producing
  - Tubing Gas Flow: 1 Mscf/D
  - % Liquid: 95
  - Liquid Below Tubing:
    - Oil: 0 %
    - Water: 100 %
  - % Liquid Below Tubing: 99 %
- Reservoir Pressure (SBHP): 863.3 psi (g)
Look Down Tubing with Acoustic Surveys to see What is Downhole

@ 4750 Ft
Tight Spot in Tubing
Bumper
Spring

@ 4325 Ft
1/8 x 1/4 in.
Small Hole in Tubing
Using an Instrumented Plunger to Determine Hole in Tubing

- Plunger Fall
- Plunger on Bottom
- Plunger Rise ->
- Plunger at Surface
- Plunger hits liquid
1. Select fall portion and zoom below

Temperature anomaly occurs due to gas entering from casing into tubing above liquid level. Drop in pressure causes cooling which is detected as instrumented plunger passes.

2. Set range to temperature anomaly

3. Find approximate depth to hole at 230 collars or 7245 ft.

Temperature anomaly occurs due to gas entering from casing into tubing above liquid level. Drop in pressure causes cooling which is detected as instrumented plunger passes.
Observations of Plunger Rise Characteristics with a Hole in Tubing

Plunger rises slowly and loses velocity until it stalls out. Rise rate is only 155 ft./min average over the first 39 collars.

Interesting to observe plunger stalls, loses liquid load and rises a few joints, then repeats several times.

Zoom in on Rise Portion of Data

TCL Count: 39
Estimated Depth: 1228 ft
Estimated Speed: 155.87 ft/min
Look now at the final rise portion of the data.

Plunger has now completely lost the fluid load and can continue to surface.

Average velocity over 308 collars is almost 400 ft./min.
Look now at the very last rise portion of the data.

The plunger travels the last 24 collars at 1317 ft./min as it comes into the lubricator. Would that be confusing? What would your thoughts be while waiting over an hour for this plunger to arrive?
Tubing Hole and Corrosion

Conclusions

• DO NOT be surprised if your liquid loaded gas wells have holes in the tubing.

• Holes cause significant drop in gas production.

• Large gas production increase is possible due to repairing the hole in the tubing and returning the gas well to unloaded flowing state.

• Shooting fluid levels to detect hole in tubing is a fairly simple process and can provide good accuracy of location.

• An instrumented plunger can quickly show the presence of a hole but is less accurate in determining location, especially if only the pressure and temperature trends are available.
Operating Parameter Issue or Tubing Set Too Low?

• The next example illustrates a high liquid producing well (>150 bbls/mmcf)
• Tubing is set 70% into the perfs (2000’ open with 11 zones)
• It is an inclined well with approximately 3000’ lateral reach at 45 degrees. Total depth 7150 ft.
• Instructive as we move more toward pad drilling with inclines and horizontal zones
• We don’t have a good answer yet for this well!
“Hand” pattern of progressive loading over 4-5 cycles until plunger fails to surface. Mandatory shut-in, then gas injection into annulus restarts pattern.

Off time and afterflow time extended to 100 minutes and approx. 30 minutes respectively (low flow cutoff at 350 mcf/d) showed temporary improvement.
Instrumented Plunger on the same well....

- Mandatory shut-in
- Gas injection
- Fast trip
- Increased loading
- Fail and repeat

Plunger fails to surface
First cycle – mandatory shut-in fails to build sufficient casing pressure to lift the load.

Plunger only moves up 105 collars at avg speed of 294 ft./min then stalls out and drops back to bottom.
Try again... this time with gas injection into the annulus at surface.....

Plunger makes a “normal” trip at a fast rate of 1195 ft./min. Lots of liquid to surface.

Gas injection on but little change in bottom hole pressure. Blockage in annulus at or above upper perfs???
The next plunger fall shows no liquid in the tubing, although there could be “mist”.

No signature pressure gradient kick that would indicate liquid.

Plunger falls at an average rate consistent with gas only at this pressure – 300 ft./min.
Fast arrival on the next trip due to minimal or perhaps no liquid load...

Plunger makes a very fast trip at a rate of 2455 ft./min. Little or no liquid to surface.
Liquid loading starts to occur....

Pressure gradient kick at 220 collars indicates 220 ft. of liquid (TD 7150 ft. minus 6930 ft.)
Rise velocity declines as loading increases...

Plunger makes a still fast but slower trip at a rate of 1552 ft./min. Some liquid to surface.
The last fall of this “hand” encounters high liquid levels...

Plunger hits liquid at 5260 ft. indicating 1790 ft. of liquid (about 7 bbls of water)
...until finally there is not enough power to lift the accumulated liquid load....

Plunger stalls out after getting only 1732 ft. off bottom and the vicious circle repeats again.
So what’s the problem?

- Lack of a casing pressure break with strong tubing pressure drop indicates blocked gas flow into tubing
- Blockage from salt, scale or ????
- Likely that tubing is simply set too deep and high liquid production means the casing gas rarely u-tubes into the tubing
- Gas injection may make the problem worse by pushing liquid back into the formation, resulting in a dry run followed by liquid rushing back into the annulus, causing cyclic pattern of unload-load-fail.
- Poorly understood influence of flow in inclined tubing, especially with the high liquid ratio and high pressures
- Problem is yet to be finally solved!
Vent or Compression Needed?

- Increasing problem to use venting as a technique in normal operation
- Regulations prohibit this as standard operating practice in many jurisdictions and the trend is to increase
- Incidences of venting will need to be documented to satisfy regulatory agencies
- Need to assess whether venting is really necessary or whether operating practice or plunger selection can solve the problem
- Last resort to add compression
What happens when we vent a well?

This is a typical example with low casing pressure over line of around 10-20 psi.

Sales valve is opened, 15 minute delay, then B-valve is opened. One hour shut-in between cycles.
Rise characteristics before vent...

Plunger gets off bottom reasonably well but stalls out after about 8-9 minutes. Avg speed only 252 ft./min.
Total average trip time can be deceiving!

If we only look at our total trip time we get a velocity of 370 ft./min. A bit slow but at least an arrival!
Let’s look at the second phase of this trip...

The plunger averages 1150 ft./min after the B-valve is opened. Comes in strong, but with little or no liquid.
What did we learn?

• Venting can be inefficient from a plunger velocity standpoint, even if it makes us feel good because we get an arrival in a difficult well
• Too slow before venting and too fast after venting means the plunger lifting efficiency is compromised at each phase of the lift cycle
• If we must vent in this case, cut the B-valve delay to about 7-8 minutes to avoid stalling
• Also reduce off time 30-50% to cut velocity when going to vent (casing pressure builds very slowly here)
• Result will be additional cycles per day at lower bottom hole pressure and more efficient liquid removal
Venting Not Needed?

• Sometimes we vent just because!
• Operating practices can tend to become “standard” and not changed even if the operating circumstances do change
• This is especially true where SCADA is not used as it is more difficult to spot trends when relying on stand-alone controllers
Well is set to open at 60 psi over line pressure with a 6 minute delay until the B-valve opens. Same thing all day every day!
Let’s look at the “average” trip....

Plunger arrives in about 6 minutes from over 11,000 ft. Notice how the bottom hole pressure builds between cycles!
How were we doing before the B-valve opened?

Not bad! Certainly running fast but did we need to vent? Plunger speed averaged over 1600 ft./min for 7800 ft.
But look what happens after going to vent...

Plunger travels the last 3400 ft. at an average velocity over 3300 ft./min!!
Was Venting Necessary?

• Obviously not!
• Bottom hole pressure build rate and corresponding Casing pressure build rate would show that plunger travel would be reliable without B-valve operation.
• Off time can be cut substantially
• May want to add a standing valve to retain liquid since the horsepower to operate looks good
• Additional cycles per day at lower pressures should enhance production and safety.
Conclusions

• Inspect well location for problems first
• Look and listen through a cycle (actual arrival rate can be vastly different than average trip time indicates!!)
• Inspect plunger for problems or wear
• Look for clues in SCADA information
• Employ additional diagnostic tools such as an acoustic device or instrumented plunger to learn more
• Be open to changing the “standard” practice
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