Ask Echometer Online Seminar – July 01, 2020

Use Acoustic Fluid Levels to Analyze and Troubleshoot Gas Wells

TOTAL ASSET MONITOR (TAM)

http://www.echometer.com/Software/Total-Asset-Monitor

"APPLICATIONB OF ACOUSTIC LIQUID LEVEL MEASUREMENTS IN GAS WELLS", McCoy, Rowlan, Collier, Podio, SWPSC 2006

"Acoustic Liquid Level Testing of Gas Wells", McCoy, Rowlan, Podio, SPE 120643

"Guidelines for the Proper Application of Critical Velocity Calculations", Sutton, Cox, Lea, Rowlan, SPE 120625

"EXCEL Spreadsheets: Critical_Velocity_with_HoleAngle.xls + LiquidLoading_Turner Graphs.pdf

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Liquid Loading of Gas Wells

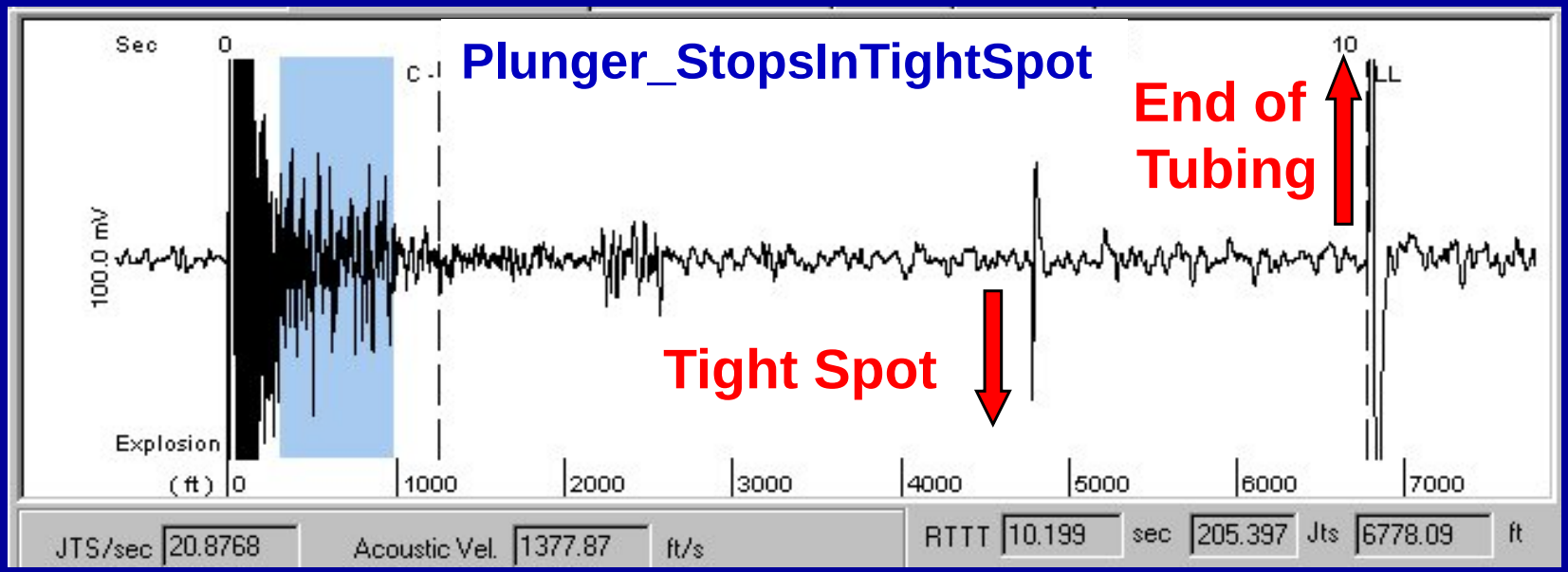
- Use Echometer Well Analyzer fluid level instrument to quickly conduct a simple test
- Measure distance to the liquid level in the casing annulus is most common use of an acoustic liquid level instruments.
- Less common technique is “shooting” the fluid level down the tubing.
- Immediately identify underperforming gas wells due to liquid loading problems.
- Fluid levels inexpensively determine severity of liquid loading for gas wells
- Traditional wire-line methods can be intrusive and costly.

Acoustic Shot Definition:

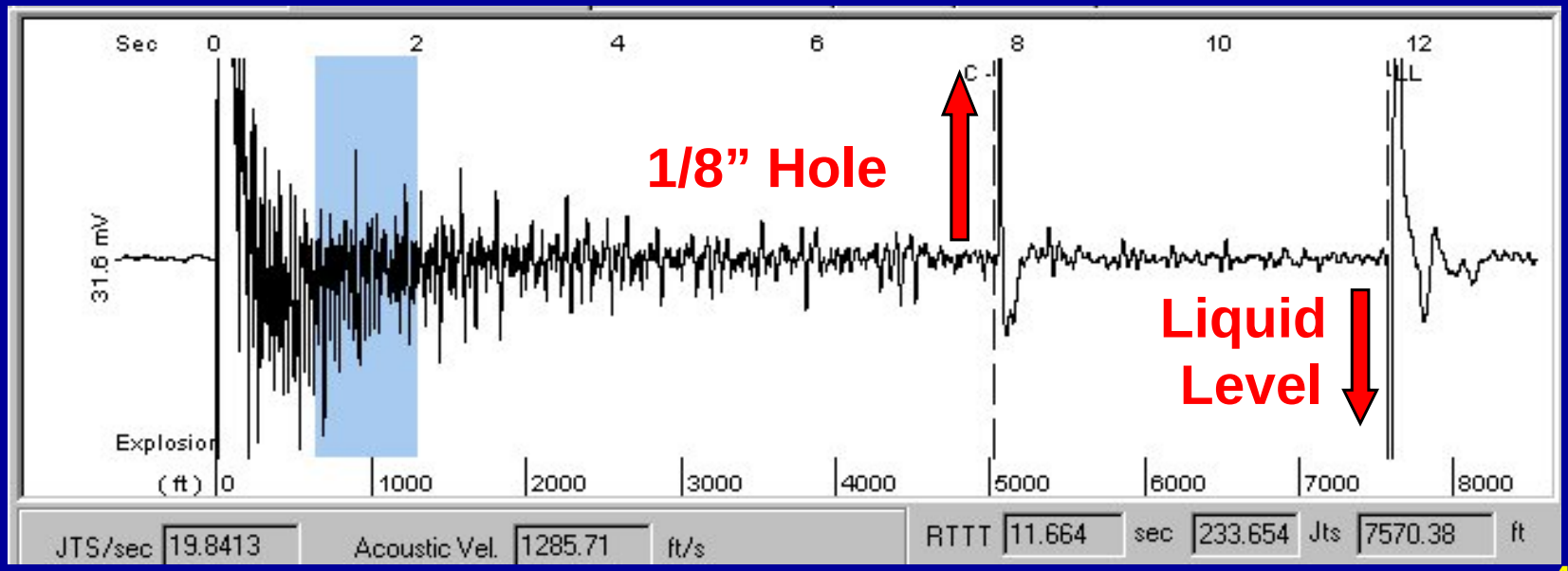
- ☒ Caused by a pressure change in a gas or liquid. – ***Bang the Shot is Fired***
- ☒ Propagate through the gas at a speed of sound called ***Acoustic Velocity***.
- ☒ Portion of ***Traveling Wave*** or sound wave is reflected by solids or liquids in the path of the wave.
- ☒ ***Echoes*** created inside a tube when reflected by changes in diameter of tube.
- ☒ The greater the change in diameter the larger is the amplitude of the reflected wave. (More Energy Reflected need ***Increased Charge Pressure***)

Use Acoustic Surveys to Alert You to What is Downhole

@ 4756’
Tight Spot
in Tubing



@ 5050’
1/8” Hole
in Tubing

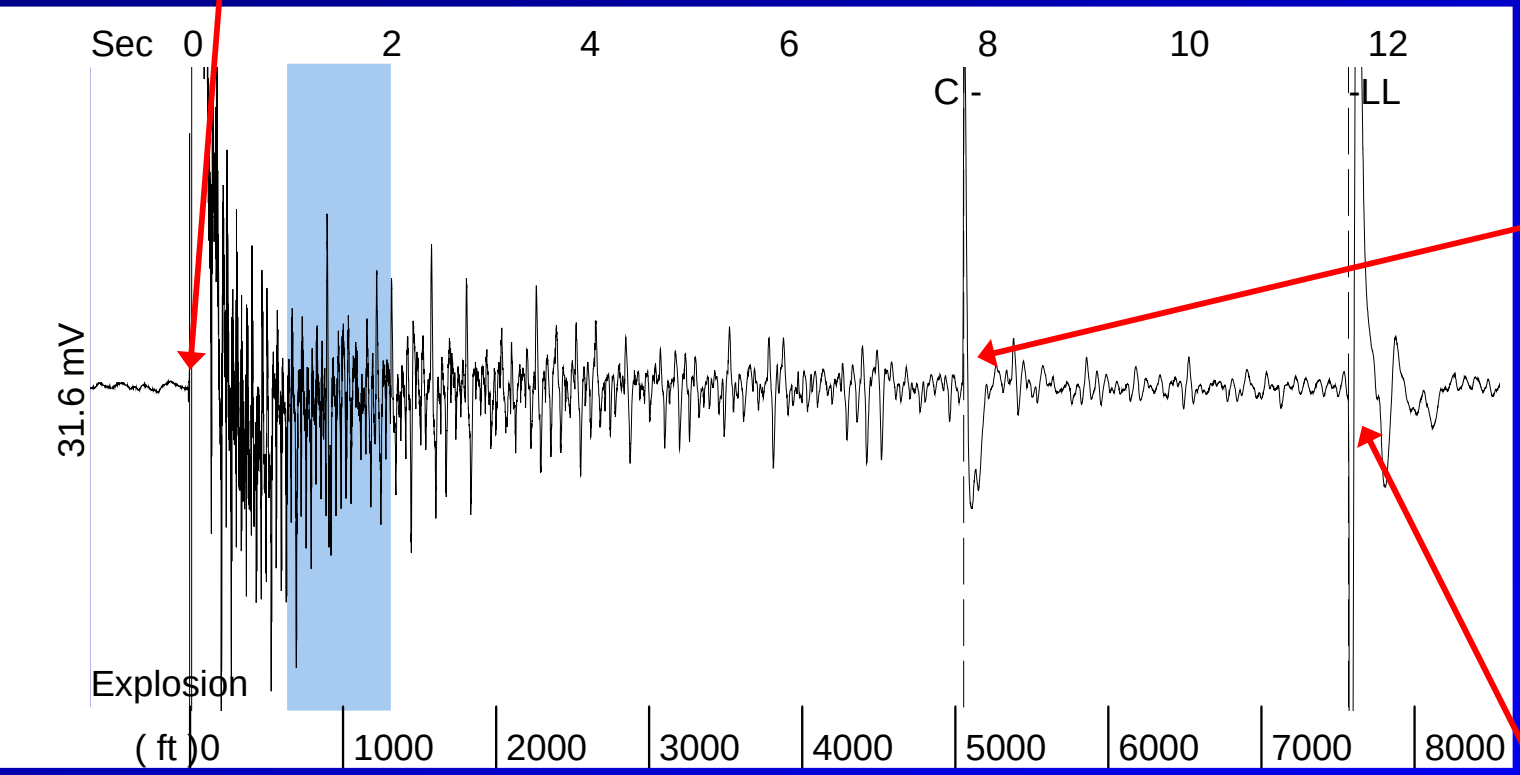


ACOUSTIC SURVEYS ON GAS WELLS ANSWER THE FOLLOWING QUESTIONS:

1. Is gas flowing? At what rate?
2. What is the depth to the top of the liquid?
3. Does liquid exist above the formation? In Tubing?
4. What is the percentage of liquid in the fluid column?
5. Does the liquid above the formation restrict production?
6. Does surface pressure restrict production? How much is the flow rate restricted due to backpressure from liquid loading?
7. What are the producing and static BHP's?
8. Does tubing gas/liquid pressure push liquid out of tubing?
9. What is the maximum rate available from the well?

Display of Reflections of Pressure Wave

Initial Acoustic Pulse – caused by explosion of compressed gas into the tubing or casing annulus, explosion into annulus forms compression traveling wave.



Reflected Pulse – caused by INCREASE in the annular cross-sectional area IS displayed as an upward kick on the acoustic trace.

Reflected Pulse – caused by DECREASE in the annular cross-sectional area IS displayed as an downward kick on the acoustic trace.

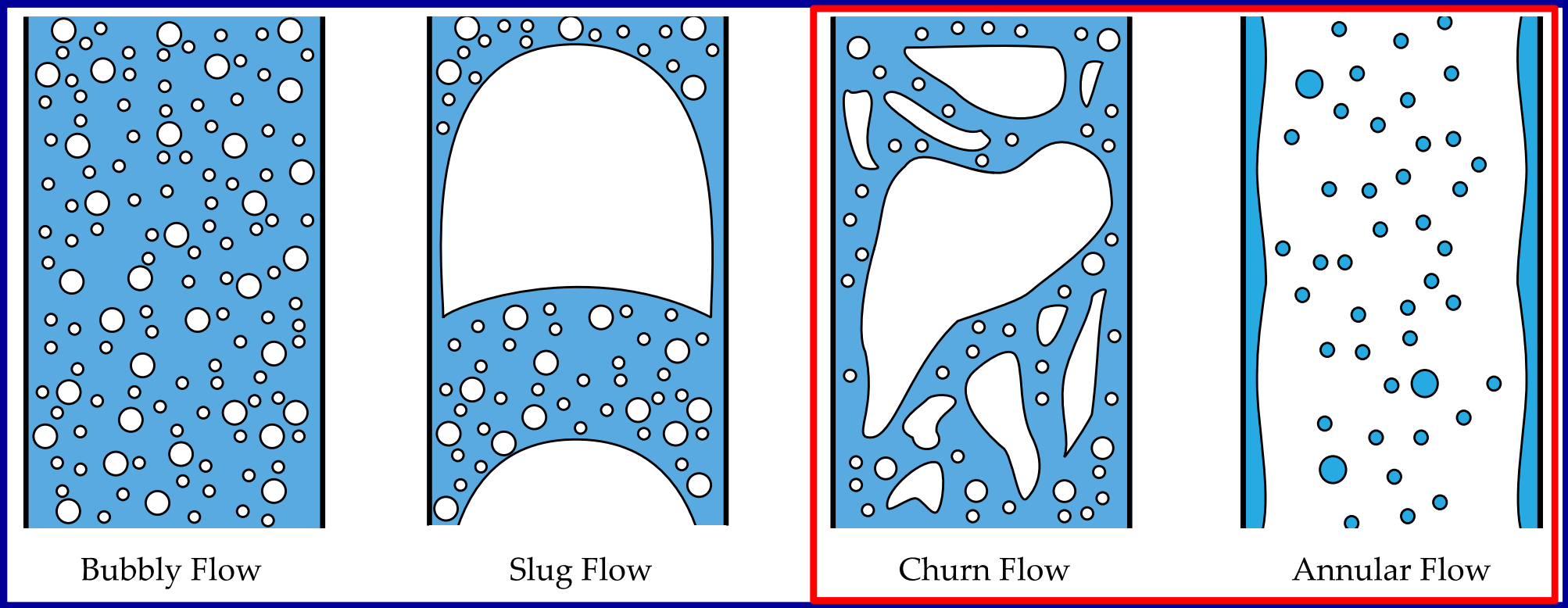
Acoustic Trace Acquired down the Tubing Showing Upkick from Hole in Tubing

Plunger_Hole in TBG

Gas Velocity Impacts Gradient

Gradient Heavy

Gradient Light



Increasing gas flow-rate

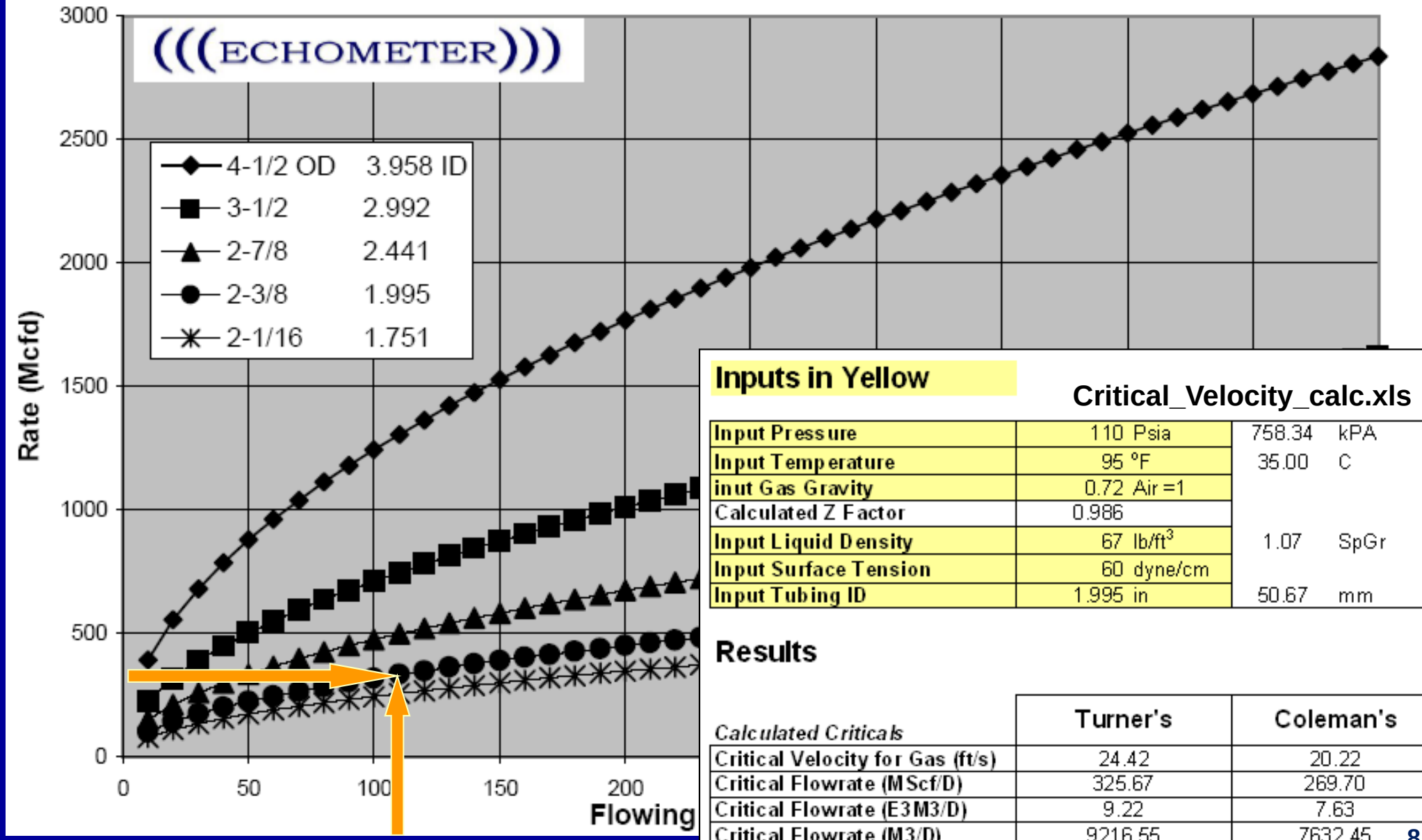
$\longrightarrow$

u_{sg} = volumetric gas flow rate / pipe cross-sectional area

Liquid Falls Back When Gas Rate Below Critical

(Lynn Rowlan, Echometer Co., Lynn@Echometer.com)
(James F. Lea, PLTech LLC (806) 239 2963, jamesflea@aol.com)

Turner Unloading Rate for Well Producing Water



Inputs in Yellow

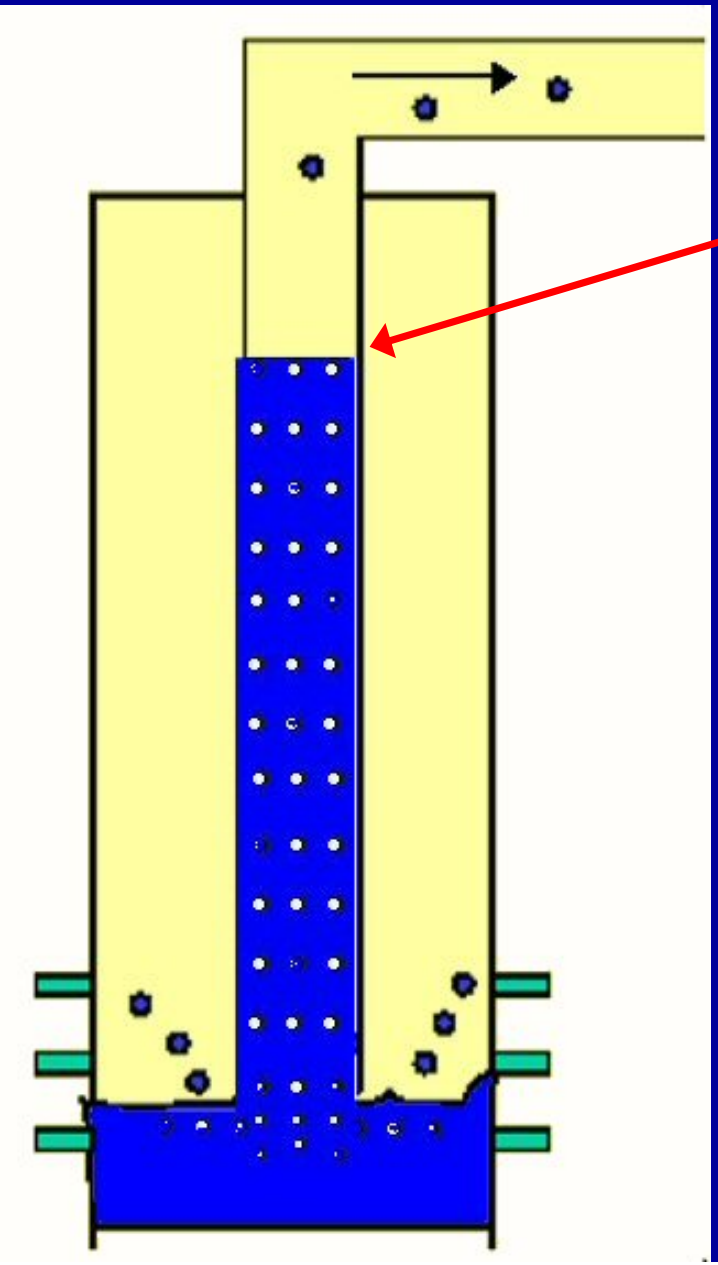
Critical_Velocity_calc.xls

Input Pressure	110 Psia	758.34	kPA
Input Temperature	95 °F	35.00	C
inut Gas Gravity	0.72 Air =1		
Calculated Z Factor	0.986		
Input Liquid Density	67 lb/ft^3	1.07	SpGr
Input Surface Tension	60 dyne/cm		
Input Tubing ID	1.995 in	50.67	mm

Results

Calculated Criticals	Turner's	Coleman's
Critical Velocity for Gas (ft/s)	24.42	20.22
Critical Flowrate (MScf/D)	325.67	269.70
Critical Flowrate (E3M3/D)	9.22	7.63
Critical Flowrate (M3/D)	9216.55	7632.45

Fluid Level on Gas Well

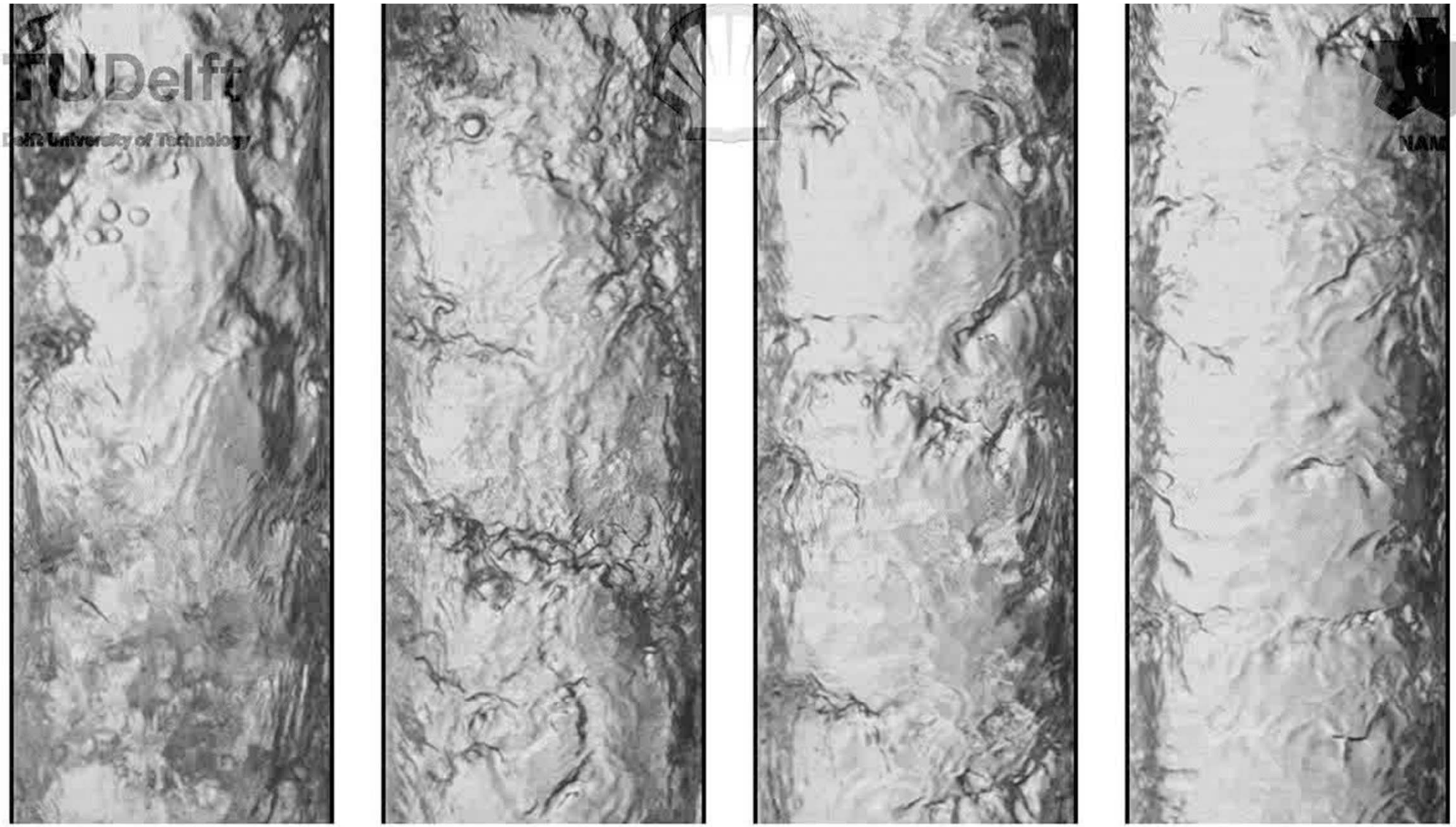


Gas Velocity Impacts Result of Acoustic Liquid Level Shot:

1. Below Critical Velocity:
   - Usually see liquid level above bottom of Tubing

2. Above Critical Velocity:
   - May not see a liquid level because liquid droplets may fill tubing and absorb all energy from shot
   - May see bottom of tubing and/or perforations due to small amount of liquid

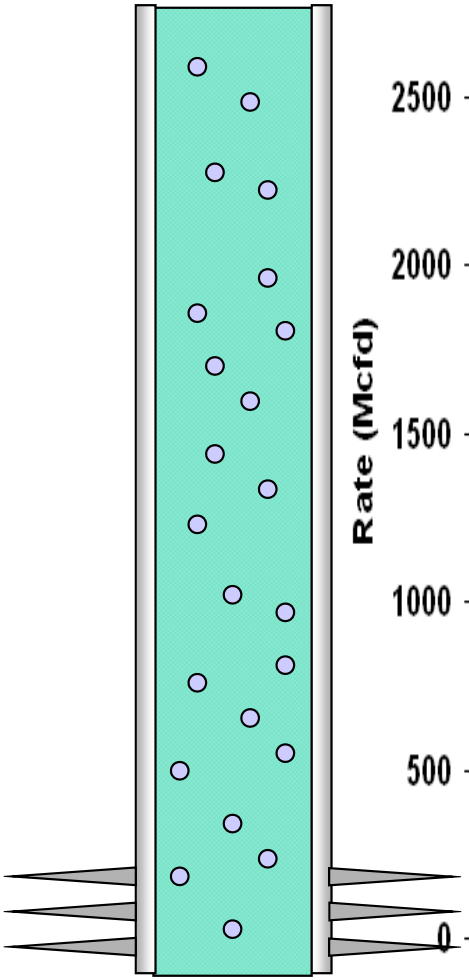
Air-water flow
(50 mm pipe, u_{sl} = 10 mm/s) from TUDelft & NAM

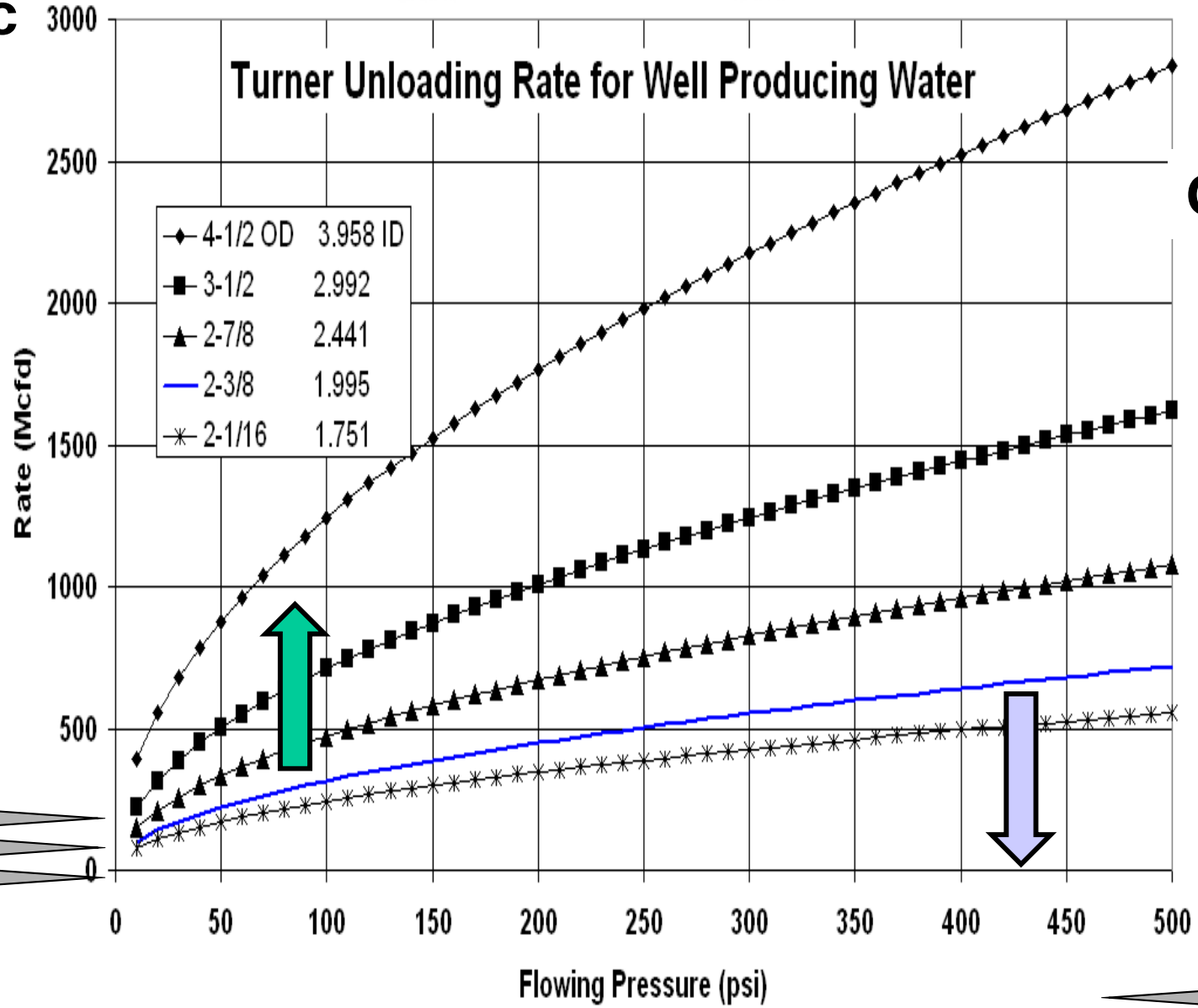


$u_{sg} = 6.4$ m/s $\quad$ $u_{sg} = 10.7$ m/s $\quad$ $u_{sg} = 16.1$ m/s $\quad$ $u_{sg} = 21.5$ m/s

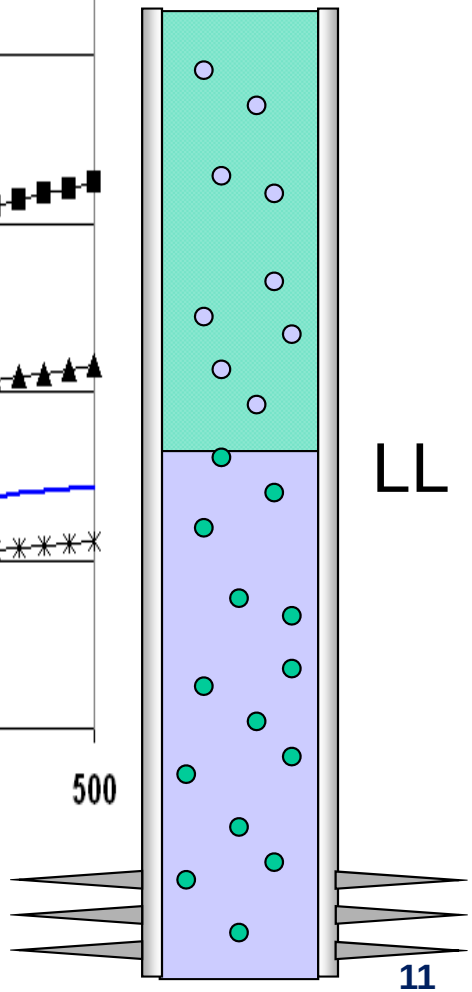
See a Liquid Level in Tubing when the Gas Flow is Below Critical Rate

Qg > Qc





Qg < Qc



Gas Gun Physical Set-up on Well

Remote Fire Gas Gun

Compact Gas Gun

5K Gas Gun

Types of Gas Well Surveys

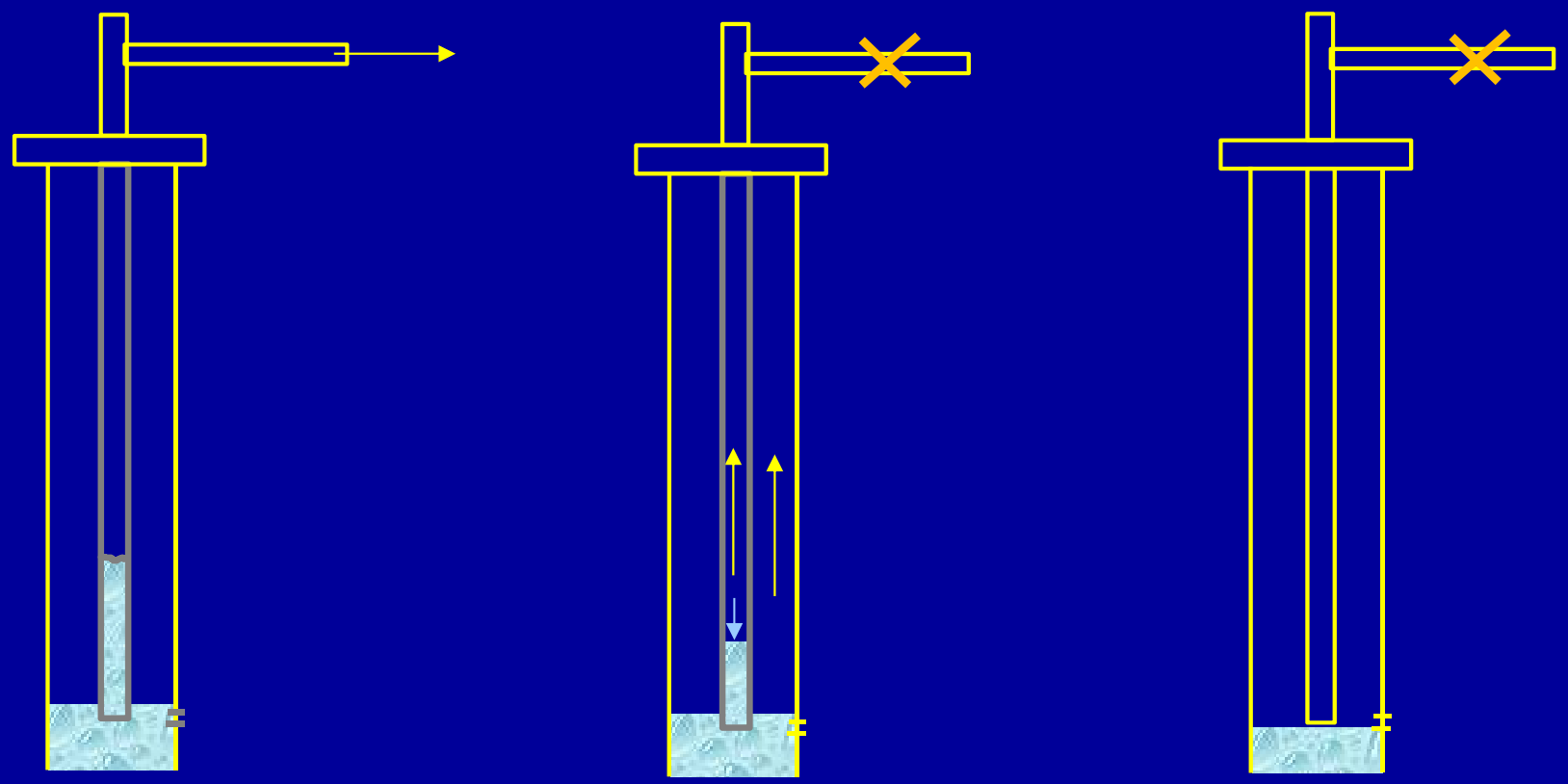
- **Liquid Level Moves w/ Change in Pressure**
  - Well is producing and Shots taken as liquid level (interface) moves
  - Flowing Gradient and BHP Determined
- L**iquid** Does not Move - **Static Shut-in Well**
  - Acquire a few shots at static conditions
- **Pump Liquid into Well**
  - Pump something in the well that moves (surfactant, corrosion inhibitor)
  - Track the top of the liquid slug down the wellbore
- L**iquid level in Casing/Tubing Annulus**
  - Casing/Packer/Tubing Integrity Testing
  - Trouble Shoot Well – Kicks do not Belong
  - Usually located at EOT

Static Fluid Level Shots

- **Tubing:**
  - **Well is shut-in**
  - **Shoot multiple shots down tubing**
  - **Shot traces should repeat**
  - **Assuming no pressure increase, only a few shots are required to verify that traces repeat**
- **Annulus:**
  - **Attach Gun to annulus**
  - **Shoot a couple of shots and go to next well**

When a Gas Well is Shut-in

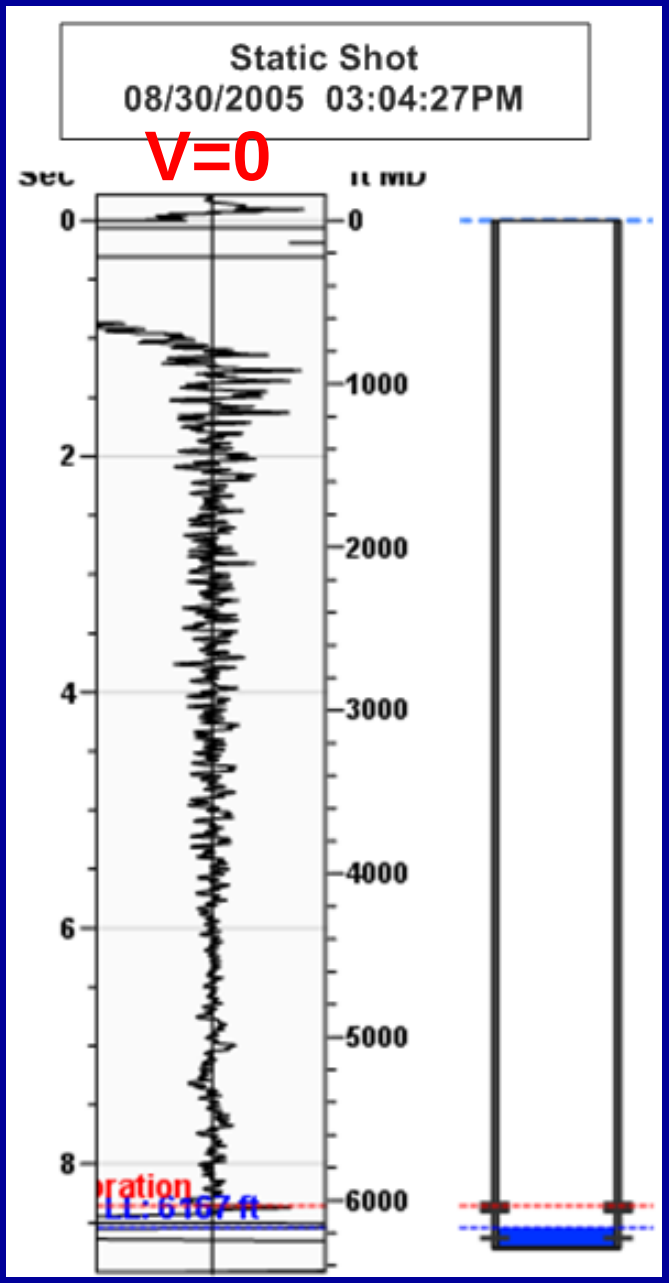
A gas well DOES NOT load up when it is shut-in!



Loaded
Flowing

Shut-in=NOT Flowing
High Pressure Gas Inflows

Static/Shut-in Gas Well (NO Gas Flow, V=0)

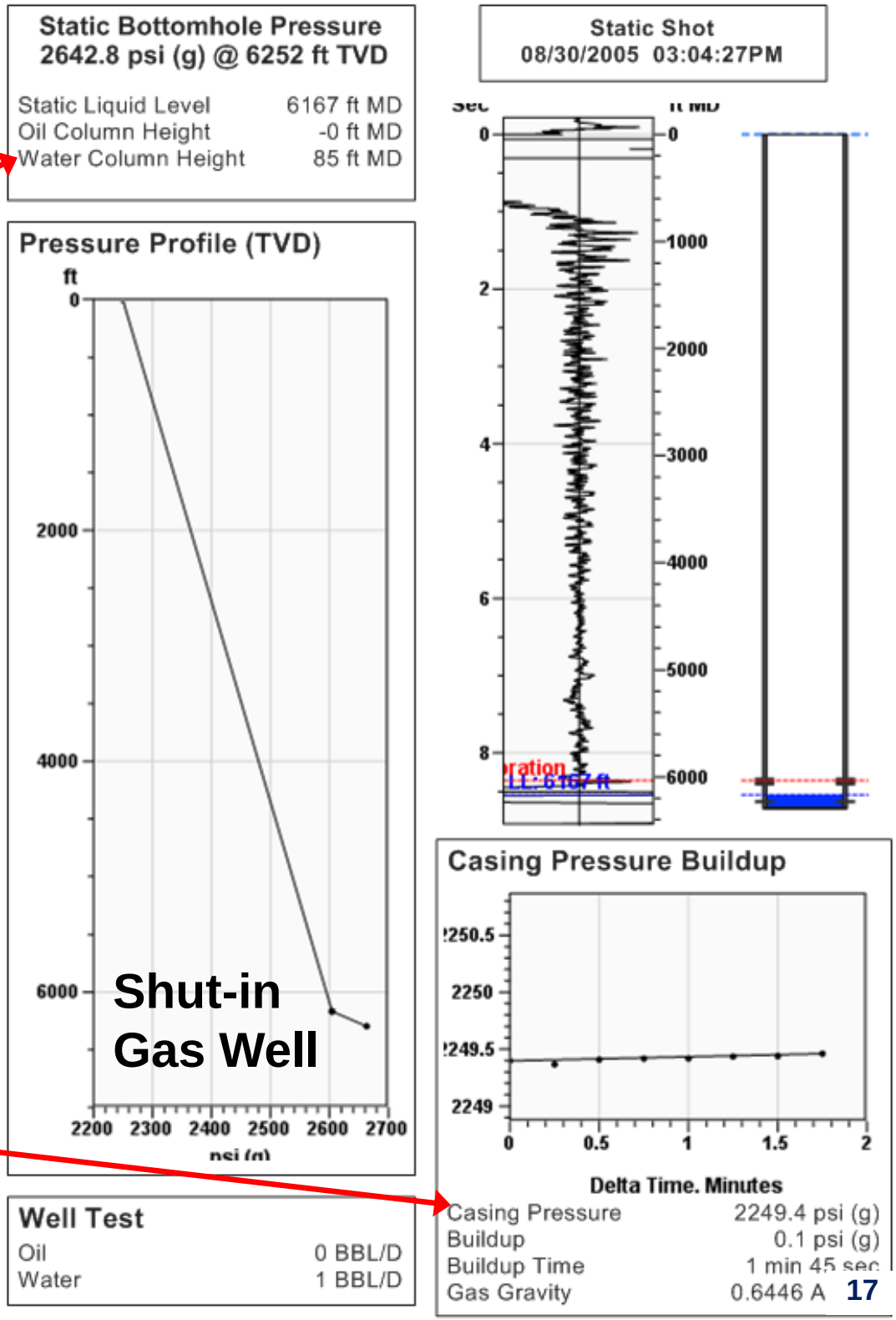


1) <u>No gas/liquid flow</u> into the wellbore.
2) Bottom hole pressure has increased until <u>all flow from the Formation Stops</u>
3) Includes wells that have been <u>shut-in for an extended time</u>.
4) Usually in shut-in gas wells the gas pressure causes <u>liquid to back flow into the formation</u>.
5) In shut-in gas wells the Liquid Level is often <u>at the perforations</u>.

Static Fluid Level on Gas Well

- High Pressure Gas Pushed all but 85.0 ft of Liquid Back into Formation
- Easy to Observe Up-kick caused by the top perfs at 6032 feet
- Collar Recesses Counted to Perforations
- Measured Surface Pressure 2249.4 Psig

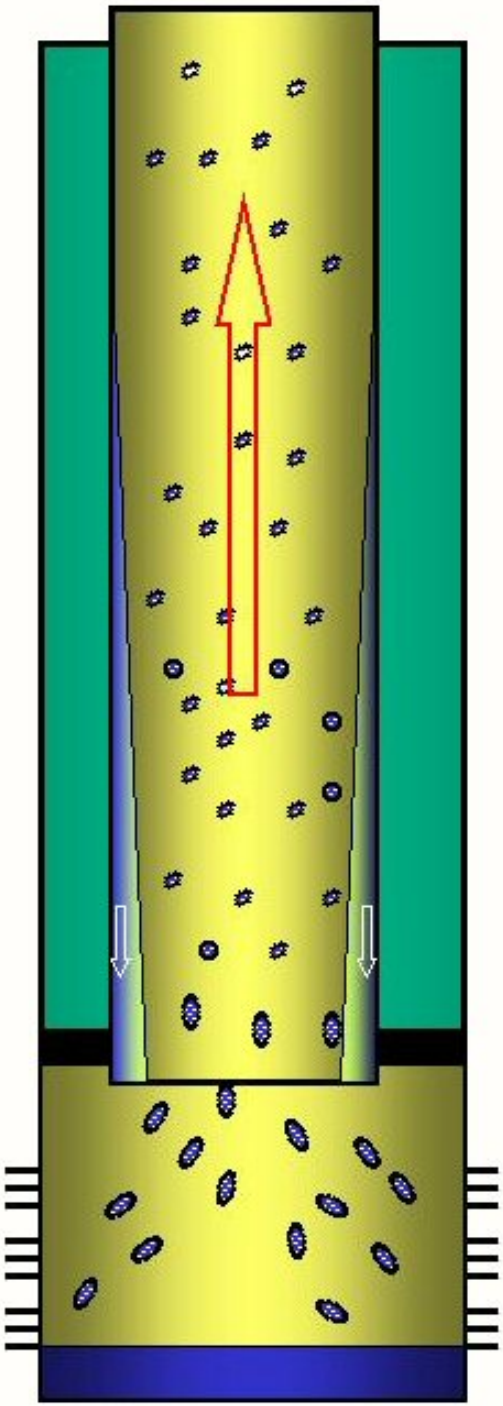
PFL_Static_GasWell_CasingOnly



Summary for transient liquid level shots

- Well must be in production until ready for shots
  - Gaseous liquid column can move quickly and go below end of tubing
  - Requires good communication with operations for planning
- Start with relatively high pressure in gas gun for shots to have best chance of seeing deep into low pressure wells
- Complete Well Data important in further analysis
- FBHP calculation is reasonably accurate

Mist {Qg > Qc} (High Gas Velocity)



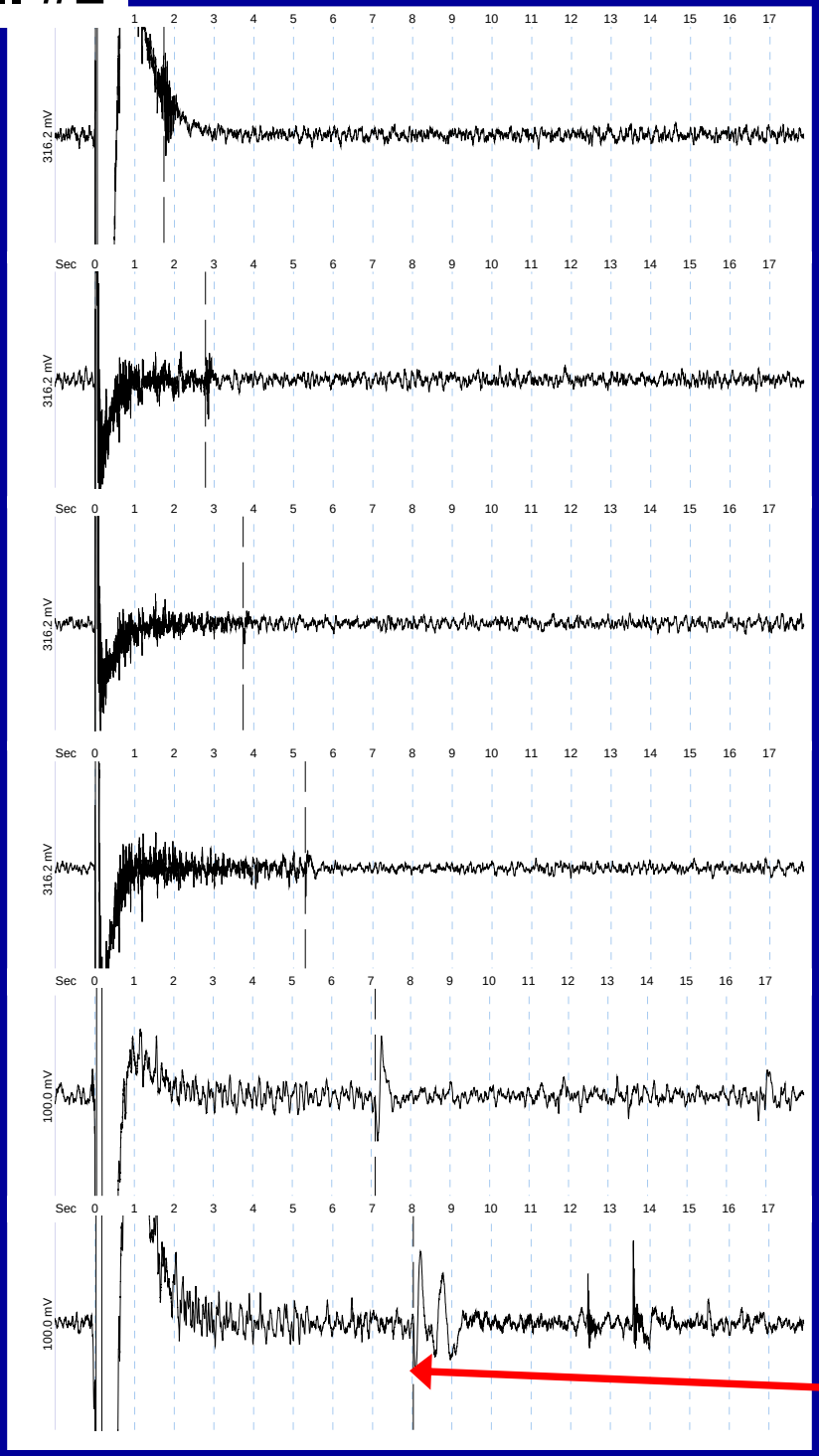
Imagine a fine mist cloud in Tubing

1) **<u>Liquid</u> being produced with the gas or condensing due to temperature and pressure changes is <u>uniformly distributed in the wellbore</u>.**

2) **Gas velocity is sufficient to continuously carry <u>liquid as a fine mist</u> or small droplets to the surface (Above Critical).**

3) **Gas velocity is sufficient to establish a relatively low and <u>fairly uniform flowing pressure gradient</u>.**

Well #1



Shots Down Tubing

Mist {Qg > Qc}

(High Gas Velocity)

Fluid Level Measurements After Shut-in

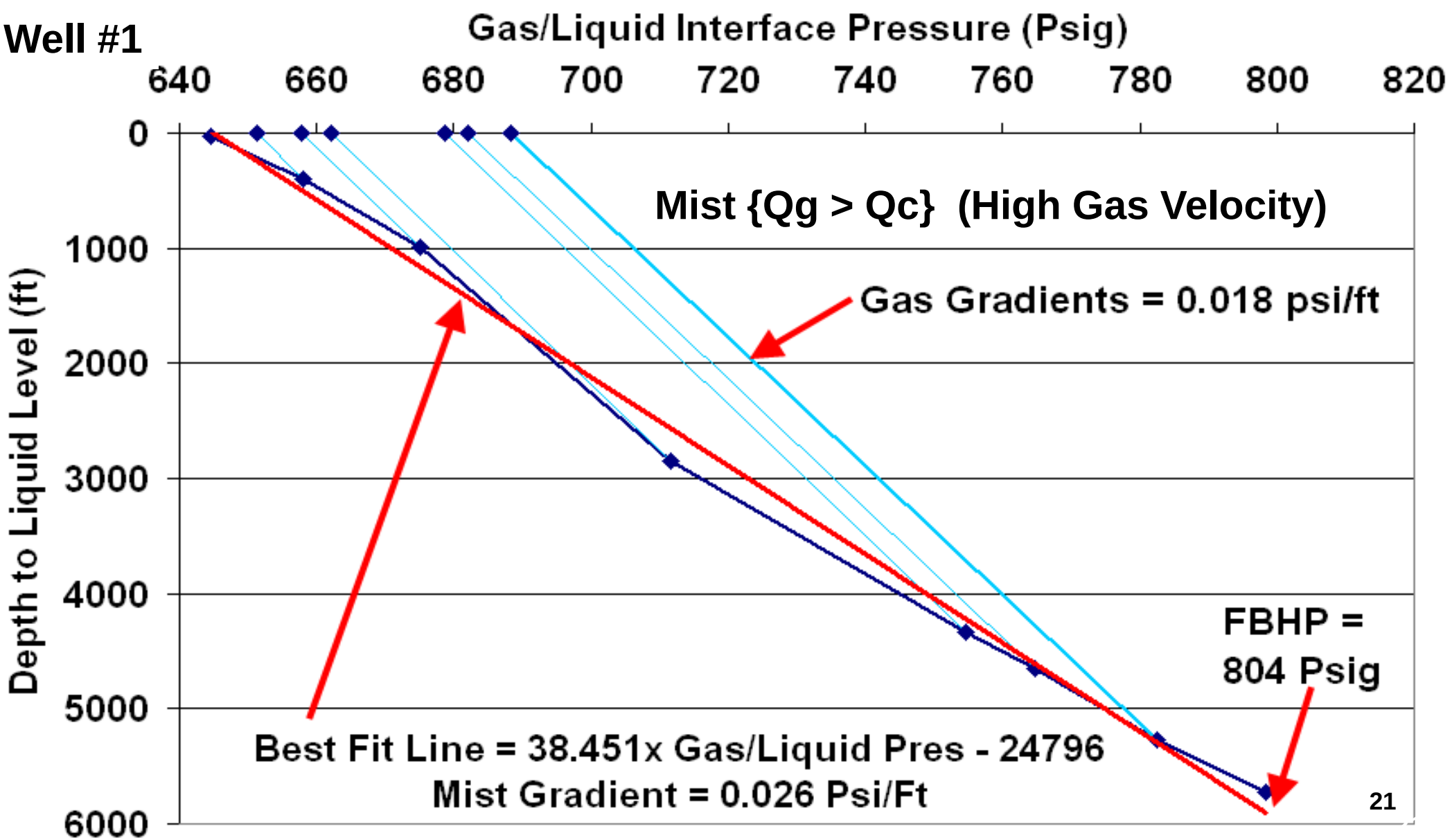
Shots taken at approximate 5 minute intervals

Should see Mist Gradient below Fluid Level

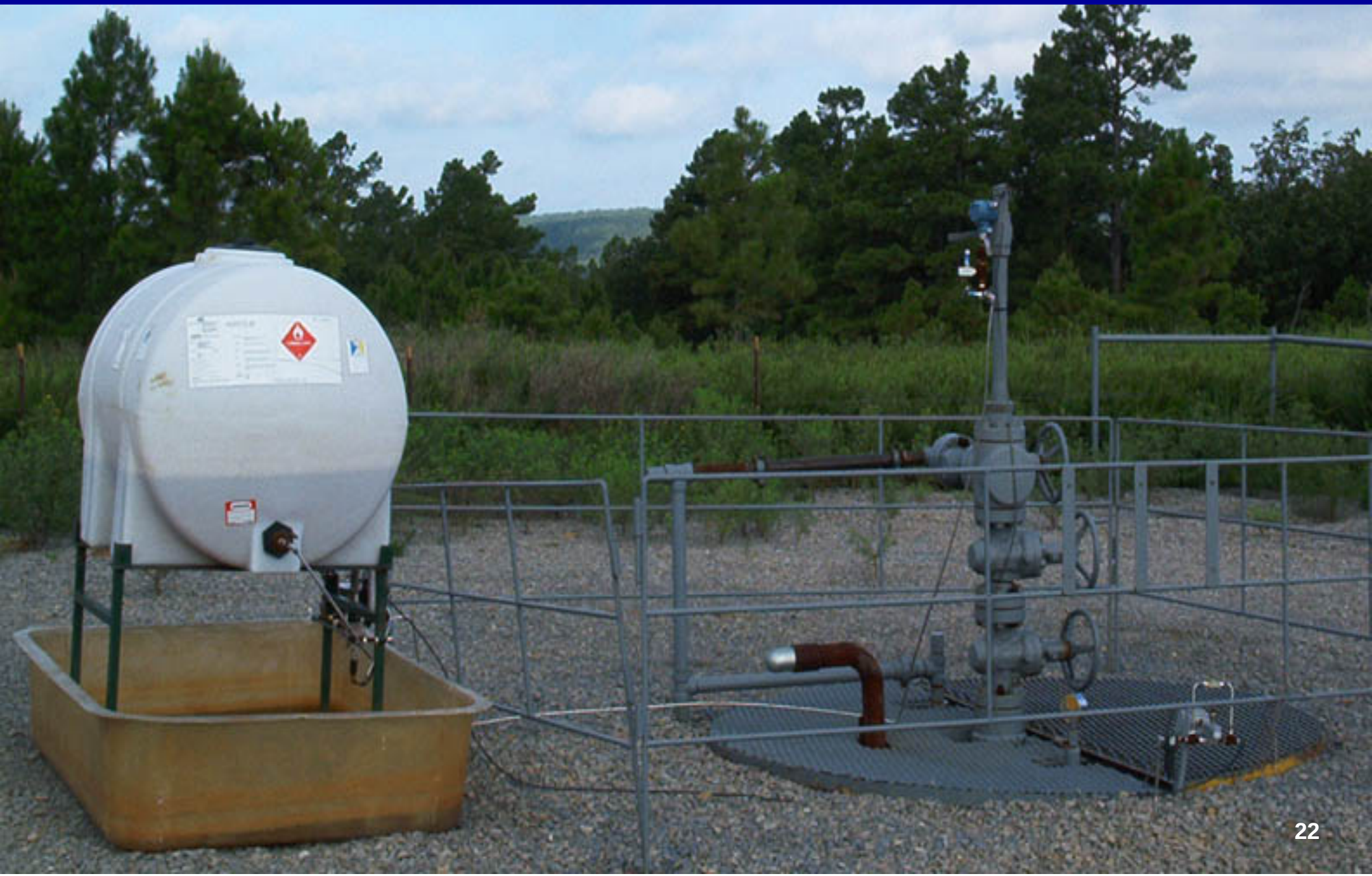
Fluid level below tubing

Use of Gas/Liquid Interface Depression Test

1) Dry Gas Gradient Above Liquid Level = 0.018 psi/ft
2) Mist Gradient Below Liquid Level = 0.026 psi/ft (6% Liquid)
3) Producing BHP is Extrapolated to = 804 psi



Shoot Tubing and Casing
Add Surfactant to Maintain Mist Flow?

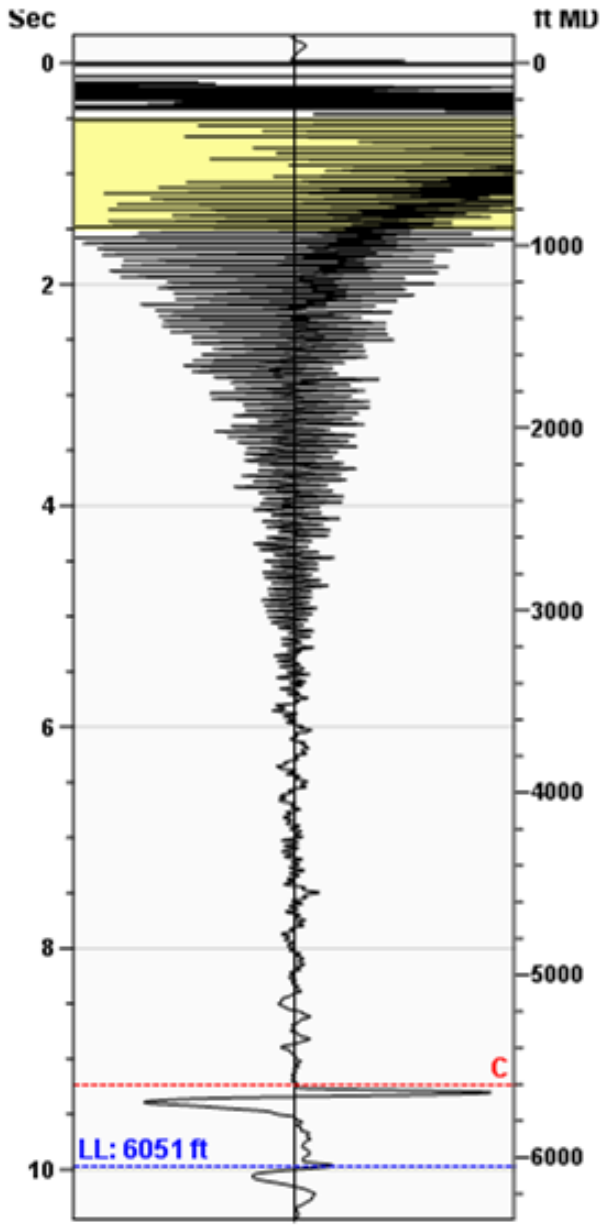


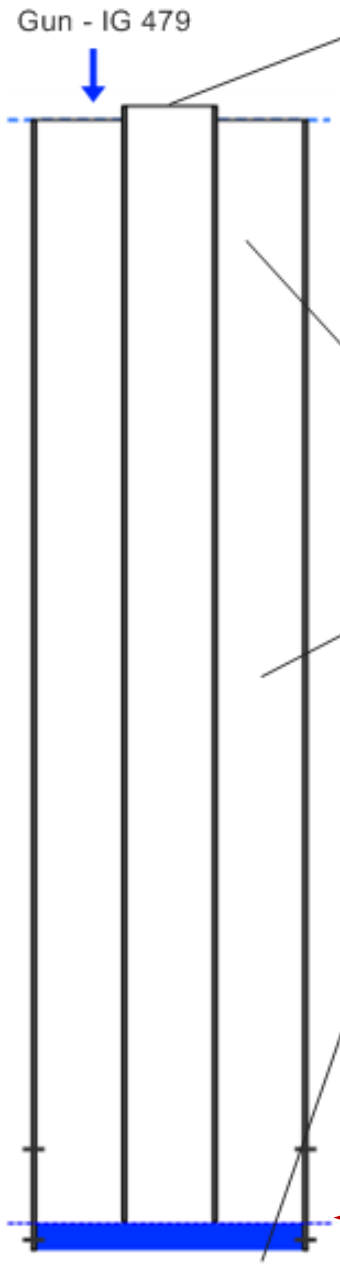
Shoot Casing : Liquid Level @ Tubing Intake

Liquid Level	6051 ft MD

Fluid Above Tubing	0 ft TVD
Gas Free Above Tubing	0 ft TVD

PFL_Foamer Down Casing





Production Modify...

Date Entered			05/21/08
	Current	Potential	
Oil	0	*.*	BBL/D
Water	1	*.*	BBL/D
Gas	31.0	*.*	Mscf/D
IPR Method			Vogel
PBHP/SBHP			-0.00
Producing Efficiency			0.00%

Casing Pressure

Pressure	150.9 psi (g)

Annular Gas Flow

Gas Flow	0.0 Mscf/D

Fluid Properties

% Liquid Above Tubing	*.*
% Liquid Below Tubing Modify...	100.00%

Depths

Tubing Depth	6040 ft
Formation Depth	6197 ft

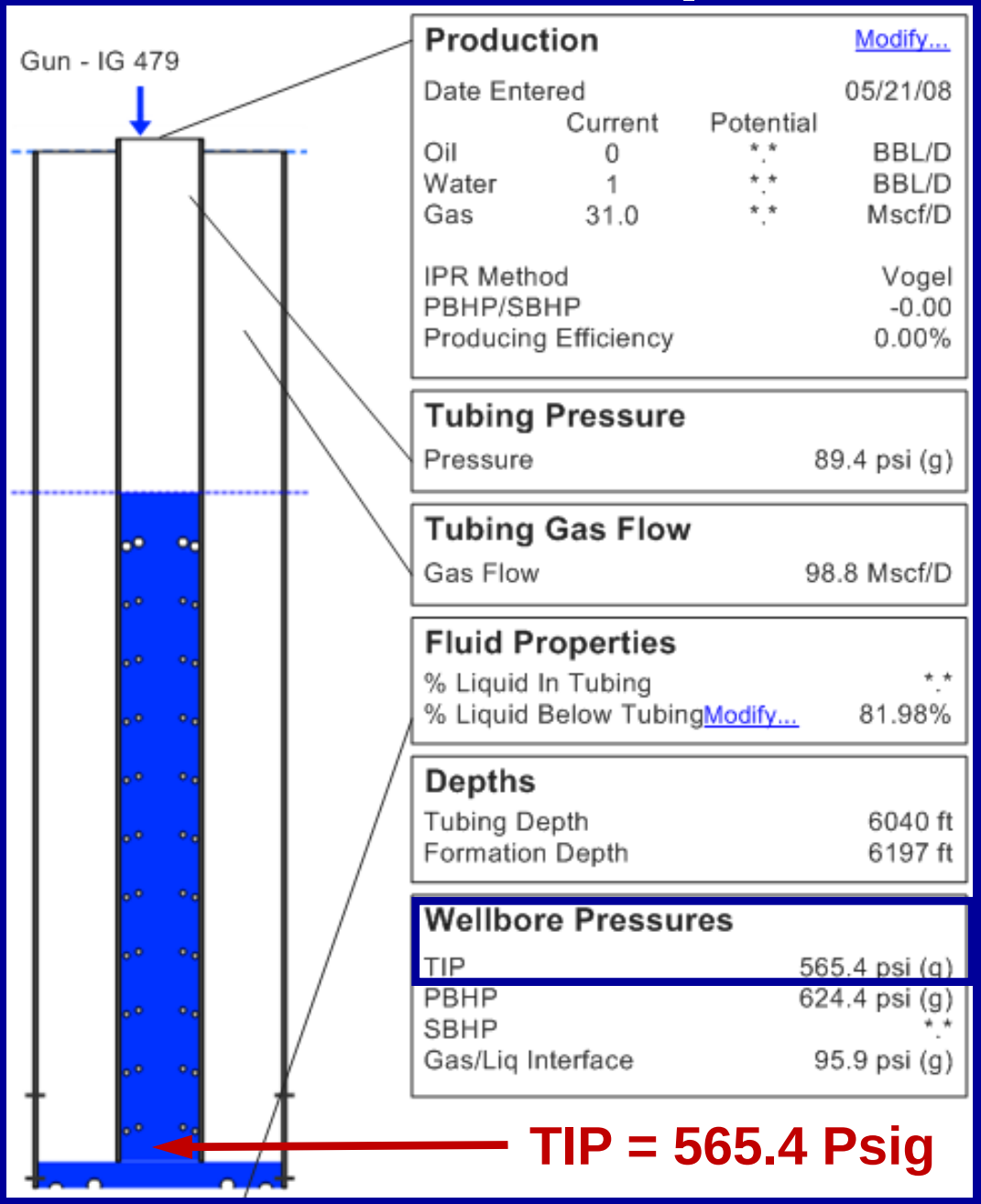
Wellbore Pressures

TIP	179.4 psi (g)
PBHP	245.9 psi (g)
SBHP	*.*
Gas/Liq Interface	179.5 psi (g)

TIP = 179.4 Psig

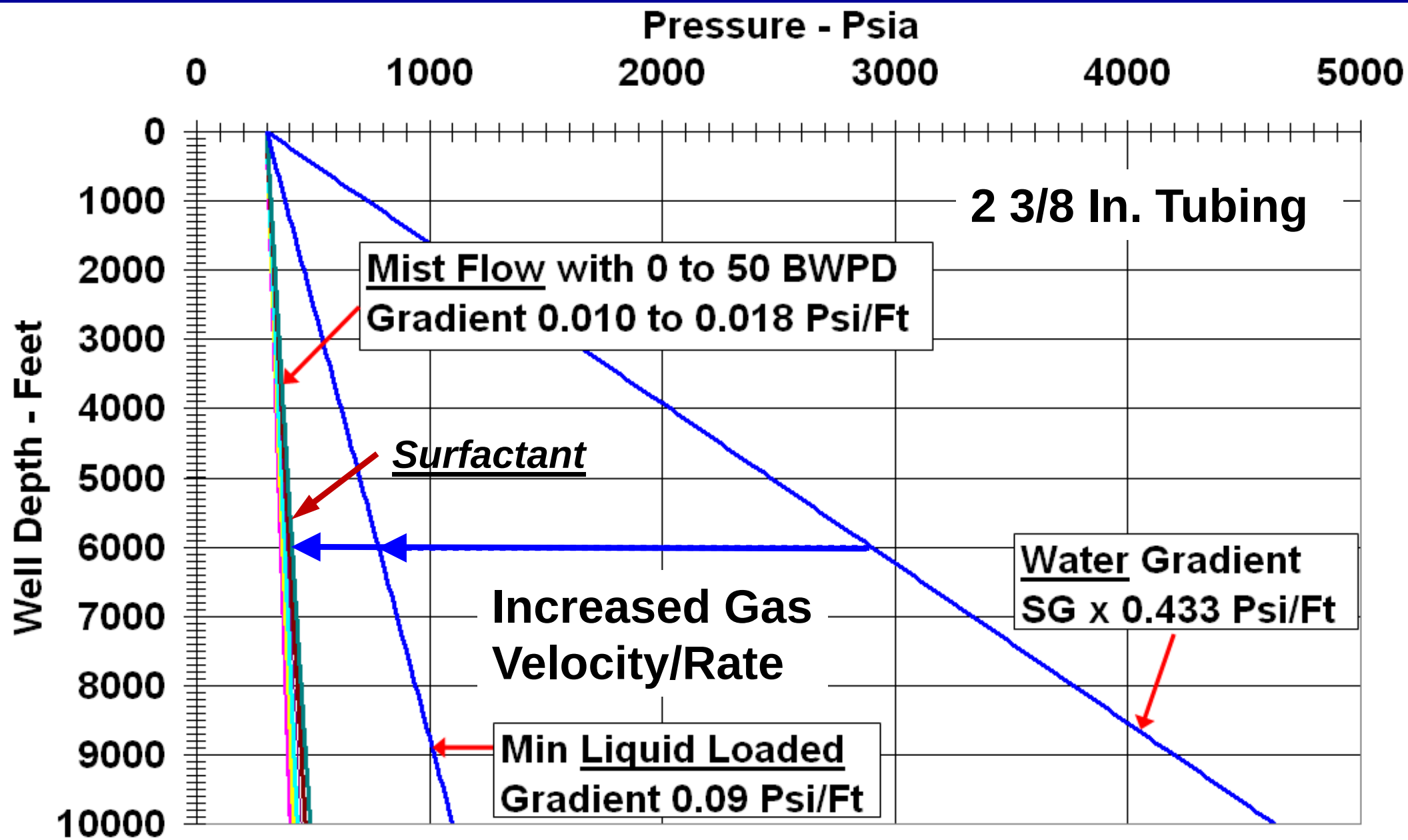
Shoot Tubing: Intake Pressures must be *Equal*!

Total Gaseous Liquid Column HT (TVD) 4003 Ft



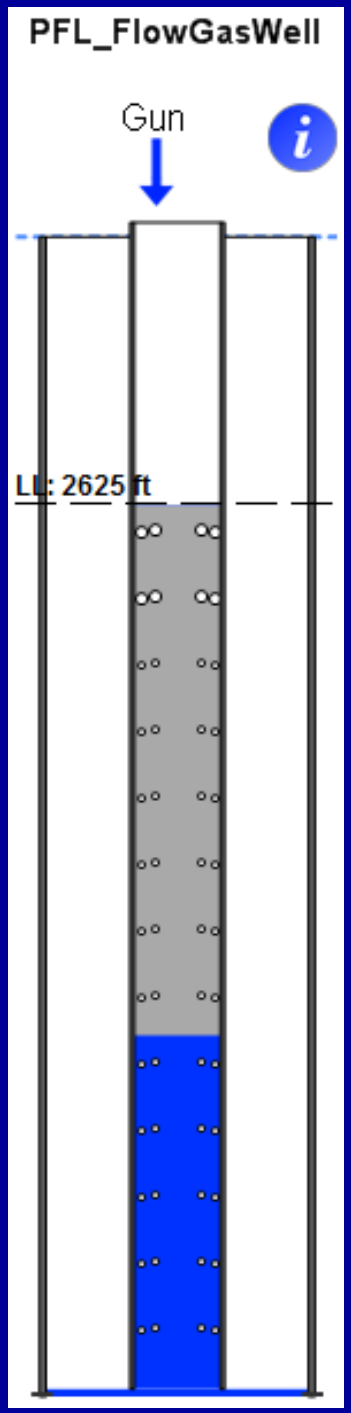
- **Casing Side Tubing Intake Pres = 179.4 Psig**
- **Shot Down Tubing:**
  - **Gas/Liquid Interface Pres = 95.9 Psig**
  - **Tubing Intake Pres = 565.4 Psig**
- **TWM 24% Liquid w/ Gradient 0.112 psi/ft**
- ***When Surfactants Used Gradients 1/3 of Typical Gas Well Fluid Level***
- **Actual Gradient: (179.4-95.9)/4003 = 0.021 psi/ft**

Flowing Gradient through the Gaseous Liquid Controlled by Gas Velocity



Foam 1/3 of Gaseous Liquid Gradient

Liquid Loaded Gas Well (VSL = 0 & Qg < Qc)



Wells Flowing Below Critical Rate:

- **Light Gas on Top**
- **Uniform Stabilized Gaseous Liquid Gradient Exist Below Liquid Level**
- **Liquid Accumulates in Bottom of Well.**

Conclusions:

1) **Initial Acoustic Fluid Levels Most Accurate in Determining Flowing BHP**
2) **Echometer Annular S-curve:**
   - **Developed Using Field Measurements**
   - **Use Down Tubing When Stabilized Liquid Loaded Conditions Exist**
   - **Does Not Calculate the Correct Gaseous Column Gradient After the Valve Is Closed for an Extended Period of Time.**

dP/dT Gaseous Correction

358 psi

Gaseous

Adjusted Gas Free

Tested Gas Production = 265 MCF/D

Tubing Pressure Buildup

15.9 psi

2.50 min

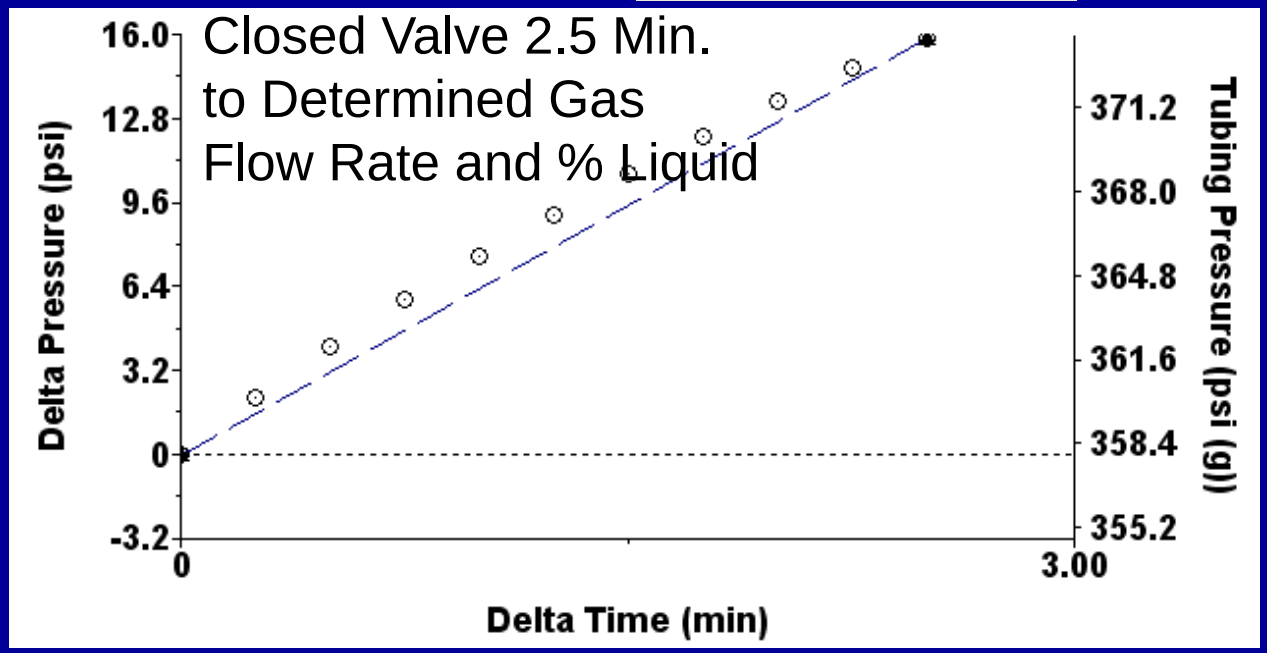
Gas Flow

135 Mscf/D

% Liquid

19

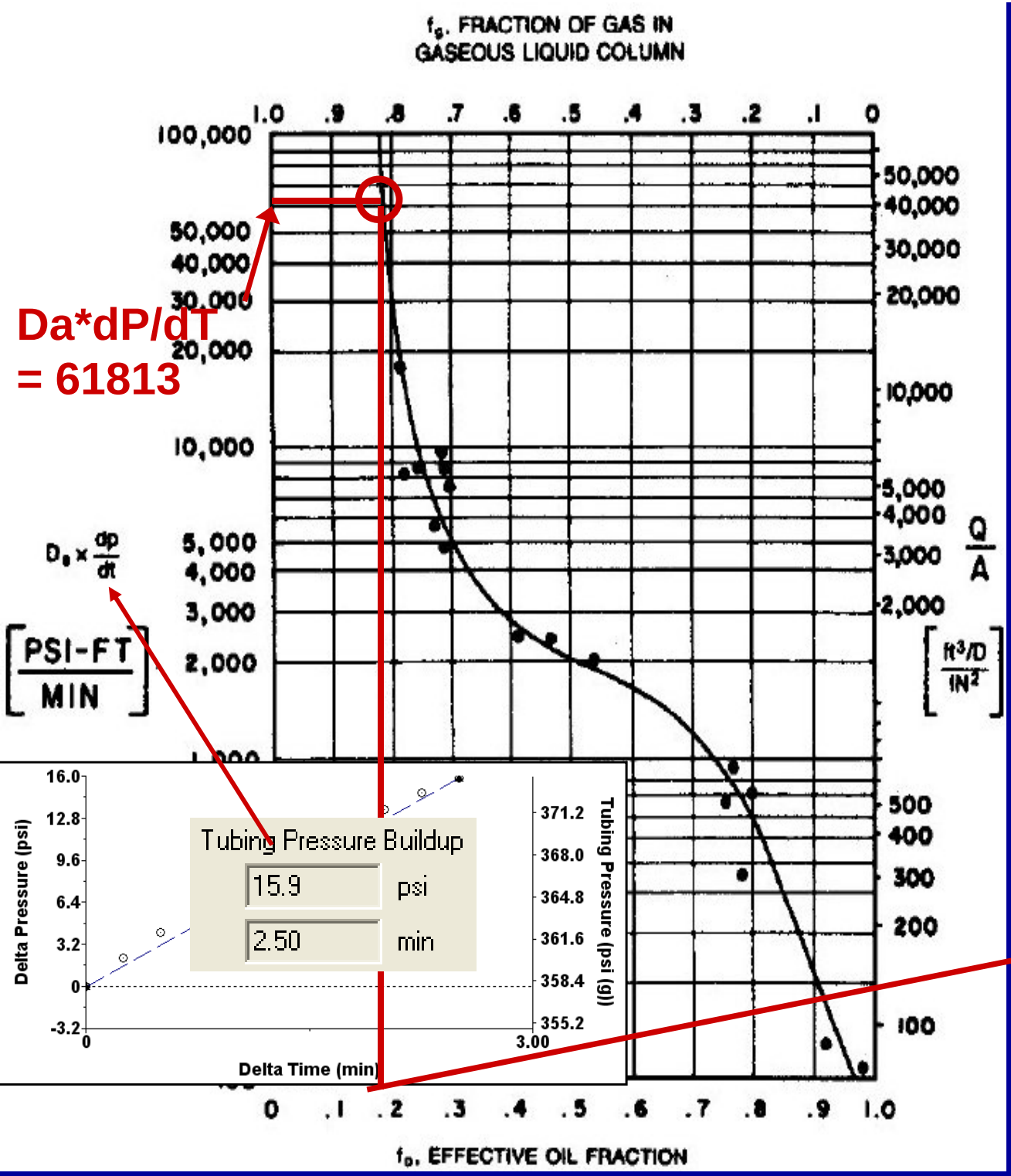
8636' Gaseous Height



1615' Gas Free

Gas flowing into well

FBHP = 1078.9 psi



Da, Adj. Gas Free Height

Da = 9719

Determine % Liquid

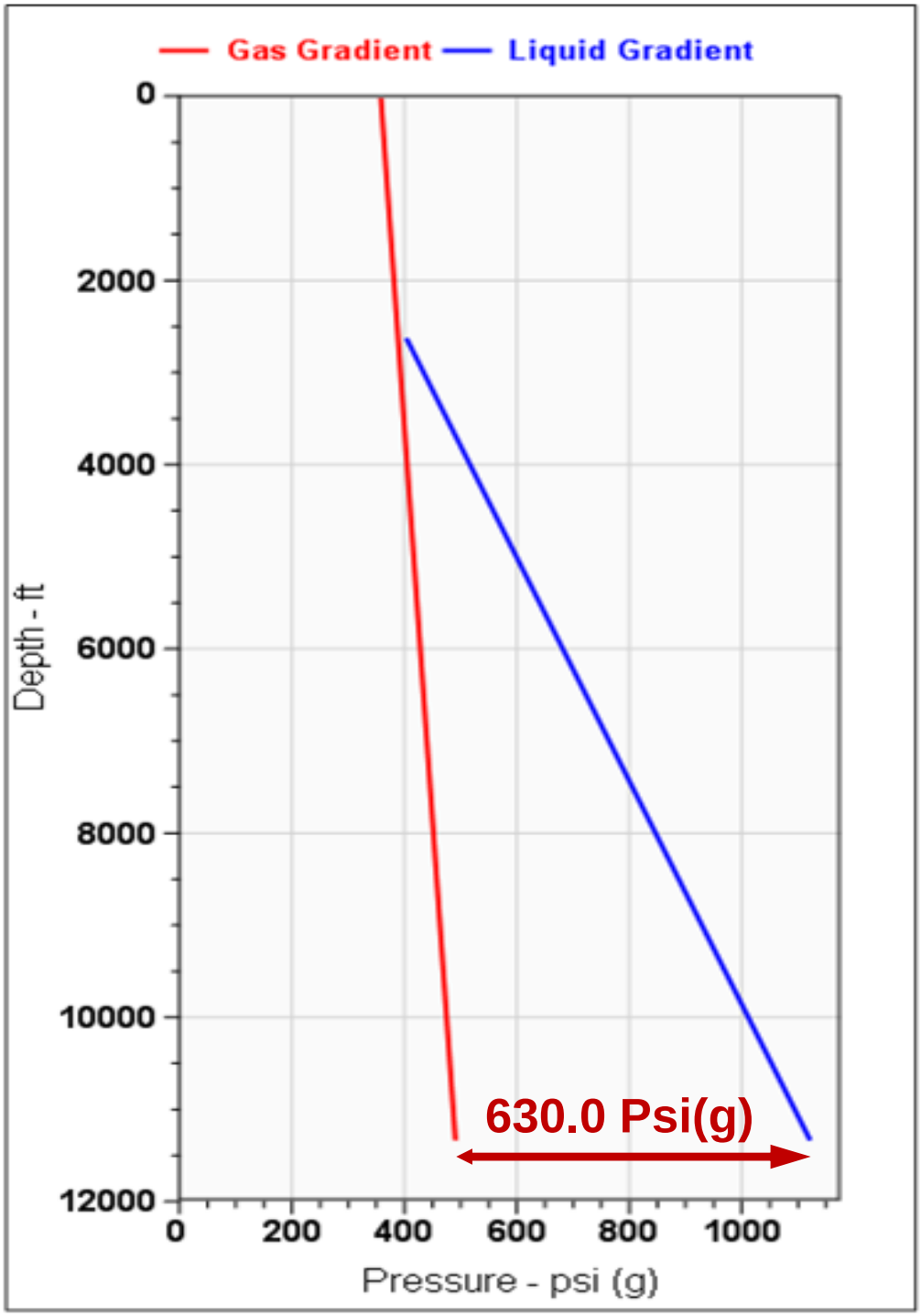
Gas Flow 135 Mscf/D

% Liquid 19

(((ECHOMETER)))

PFL_FlowGasWell 12/06/2000
03:32:40PM

Deliquification | Producing



Production

Modify...

	Current	Potential	
Date Entered			12/06/00
Oil	1	2	BBL/D
Water	1	1	BBL/D
Gas	265.0	413.6	Mscf/D

IPR Method	Vogel
PBHP/SBHP	0.55
Producing Efficiency	64.07%

Calculation for Continuous Removal of Liquid

Modify...

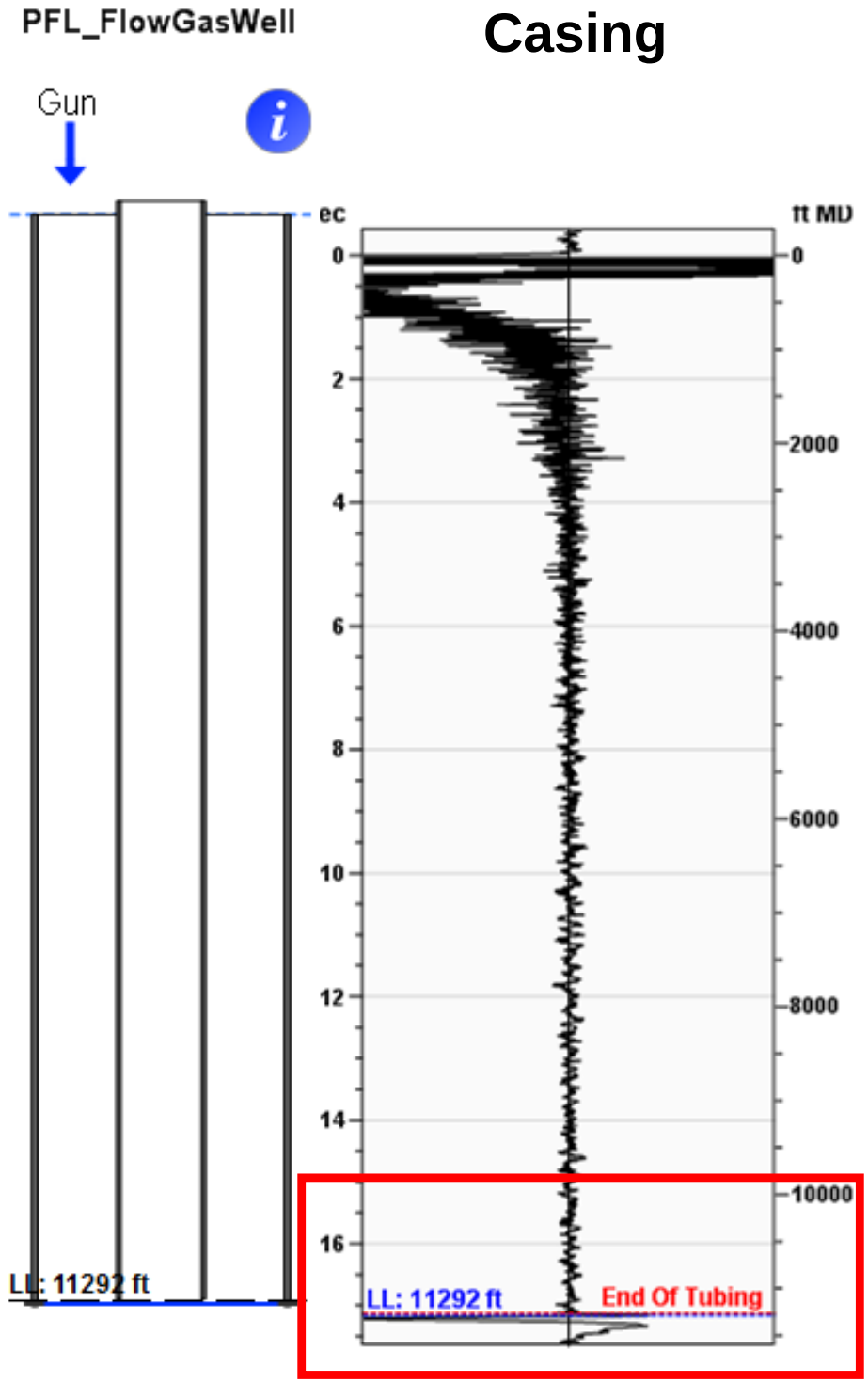
Method	Turner Critical Velocity for Gas Wells
For Tubing ID	2.441 in
For Water	1018.2 Mscf/D
For Condensate	657.4 Mscf/D
Back Pressure on Formation Due to Liquid Loading	630.9 psi (g)

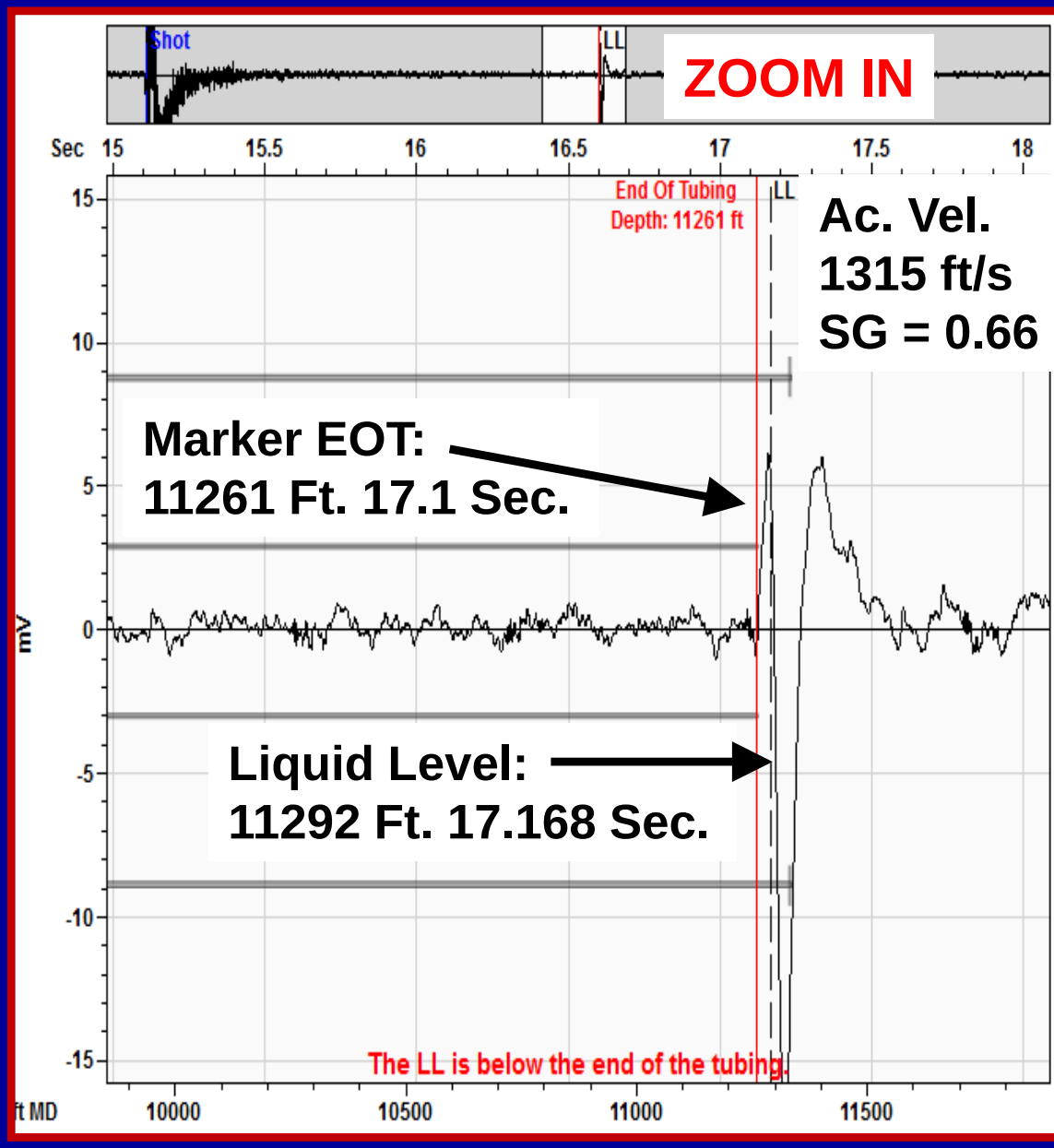
Tubing ID in	Gas Rate Mscf/D	Predicted Status
2.441	265.0	Loaded
1.995	265.0	Loaded
1.500	265.0	Loaded
1.250	360.2	Flowing
1.000	337.2	Flowing

Pressure

Surface Tubing	358.0 psi (g)
Gas/Liq Interface	403.4 psi (g)
Current Loaded EOT	1121.6 psi (g)
Flowing Gas EOT	490.7 psi (g)
Back Pressure	630.9 psi (g)
Static Bottom Hole	2000.0 psi (g)

Casing Fluid Level Should be at EOT





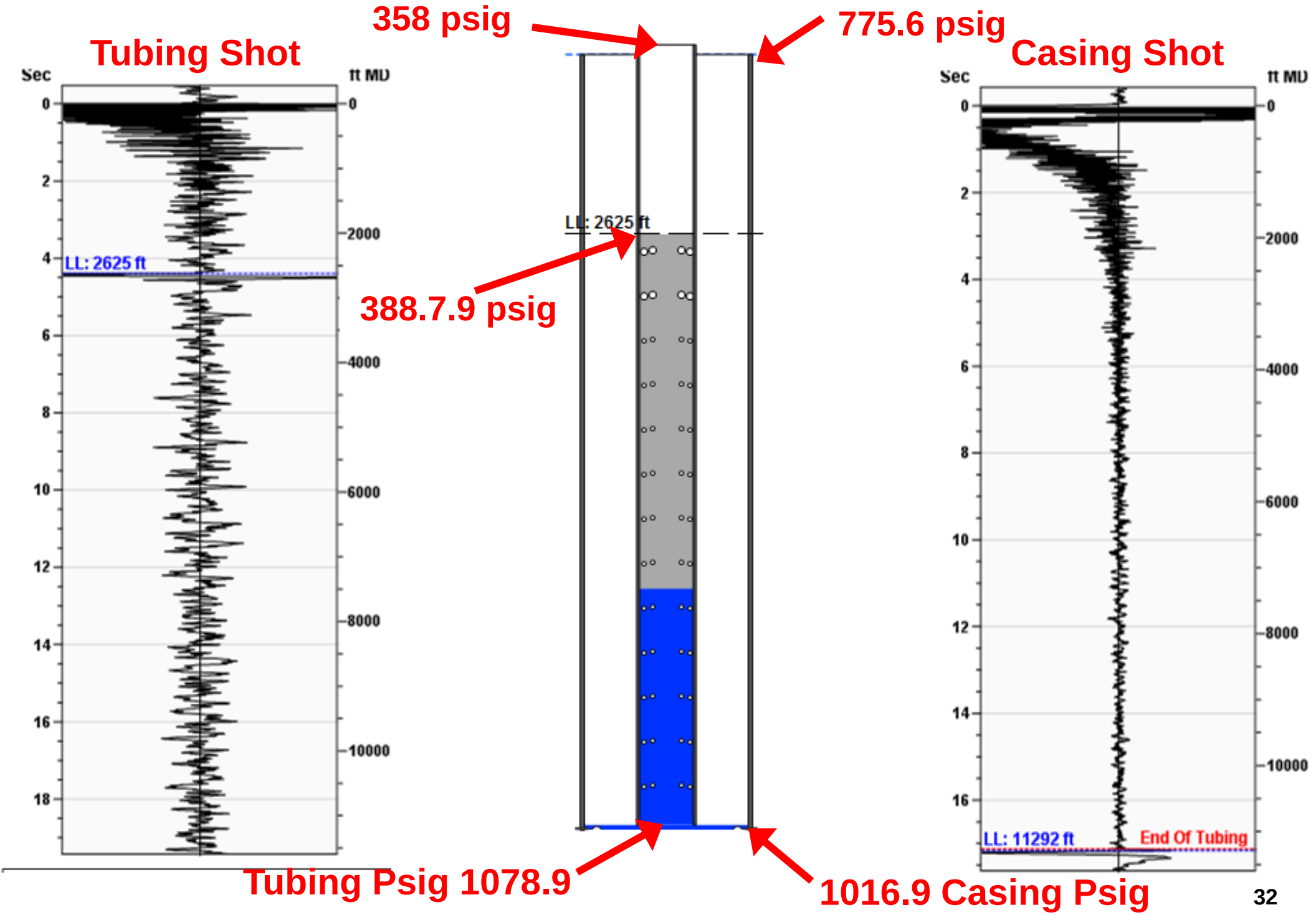
Tubing and Casing Fluid Level Acquired on Stabilized Well

1. Volume of Liquid in the tubing =
   .00224176 (Pcasing-Ptubing) (Tbg ID_^2)/ SpGr of Liquid
   Where .002241 =1/ 0.433 * (3.14 /(4*144)) *(1/5.615)

2. Height of Gassy Liquid In Tubing – ft
   =(Pcsg-Ptubing)/ (.433 * SpGr * (1-Gas Fraction))

- Fluid Level in Casing at EOT ~ No Packer.
- Tubing Liquid Loaded and Below Critical Rate ~ No Surfactant or Mist Flow.
- Flow up Tubing is Stabilized ~ Not Shut in for Extended Time Period.
- Standing Valve in Tubing can Hold Liquid Pressure in Tubing

Pressure at EOT should be Equal

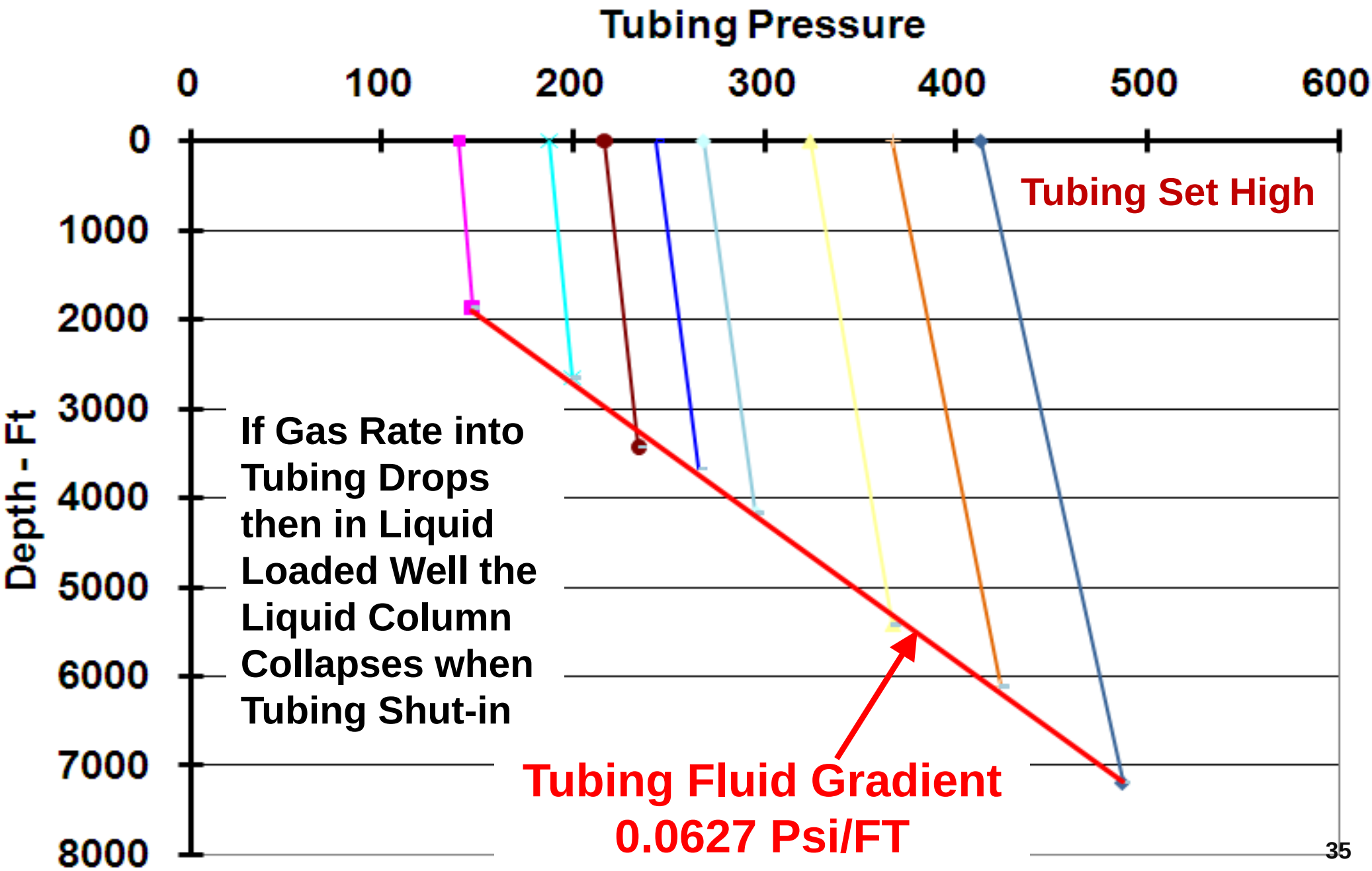


Liquid Loaded Gas Well – Tubing Set High

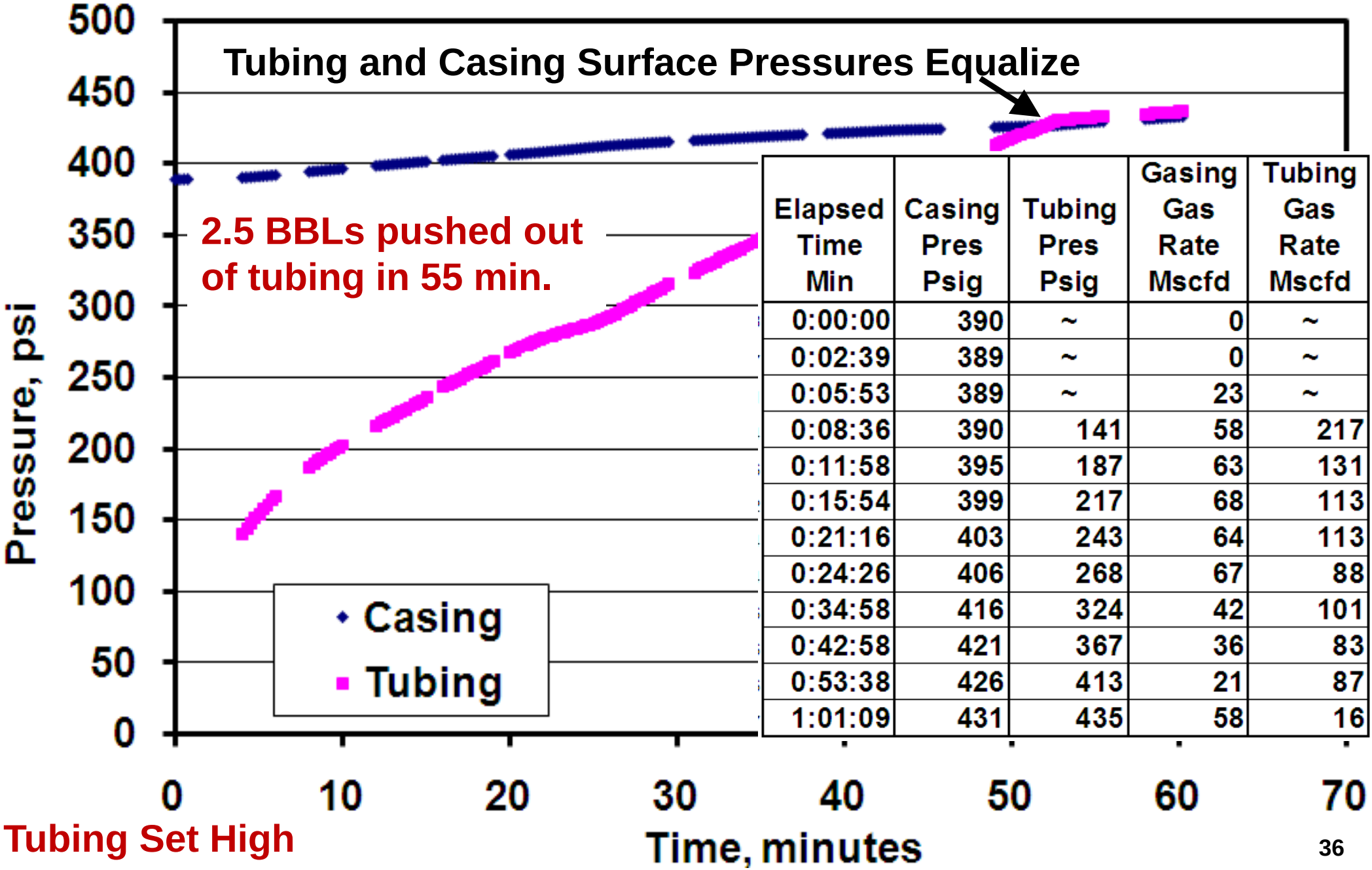
- In liquid loaded gas well fluid level data was acquired simultaneously down the tubing and casing.
- Well was liquid loaded and the tubing was set above four sets of perforations (tubing is set too high).
- Accumulating gas pressure pushed the liquid out of the tubing; with small impact on the gas rate from the formation.
- In Liquid Loaded Well w/ Tubing Set High Gas flows
  - 1st into the tubing in order to push out liquid loading
  - Once liquid pushed out of tubing, then gas flows equally into casing & tubing based on area
- A standing valve is needed in wells where produced by plunger lift and tubing is set tooo high.

Simultaneous Shots Acquired Down Tubing and Casing

Tubing Fluid Gradient Remained *Constant* as Gaseous Liquid Pushed Out



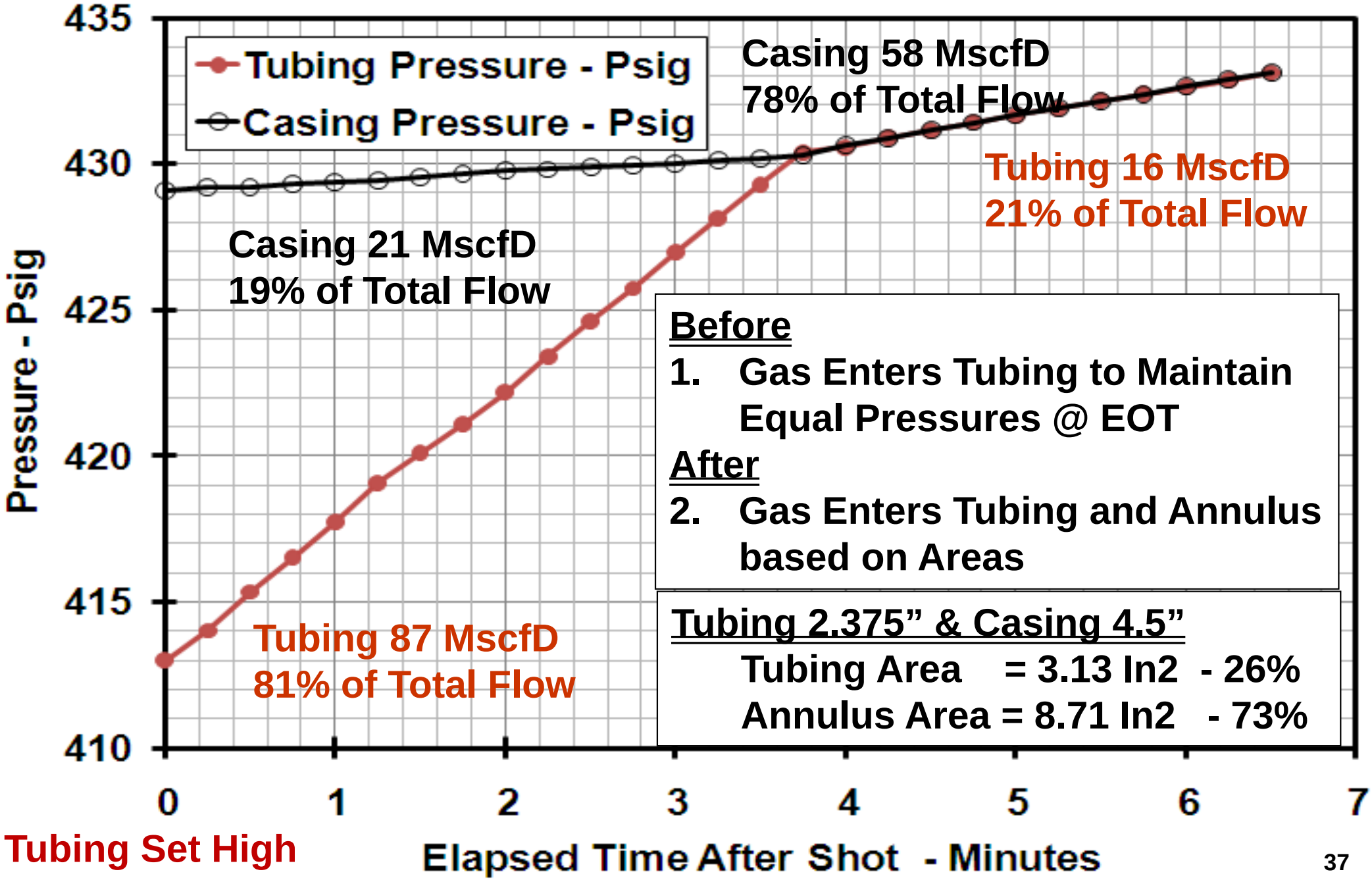
As Pressures Difference Decreases Gaseous Liquid is Pushed Out of Tubing



Elapsed Time Min	Casing Pres Psig	Tubing Pres Psig	Gasing Gas Rate Mscfd	Tubing Gas Rate Mscfd
0:00:00	390	~	0	~
0:02:39	389	~	0	~
0:05:53	389	~	23	~
0:08:36	390	141	58	217
0:11:58	395	187	63	131
0:15:54	399	217	68	113
0:21:16	403	243	64	113
0:24:26	406	268	67	88
0:34:58	416	324	42	101
0:42:58	421	367	36	83
0:53:38	426	413	21	87
1:01:09	431	435	58	16

Tubing Set High

Tubing & Casing Pressures Equal When Gaseous Liquid is Pushed Out of Tubing



Tubing Set High

Turner Unloading Velocity

$$v_c = 1.5934 \underbrace{\left[\frac{N_{we}}{30}\right]^{0.25}}_{\text{Turner Adjustment}} \left[\frac{\sigma\left(\rho_l - \rho_g\right)}{\rho_g^2}\right]^{0.25} \underbrace{\frac{\left[\sin\left(1.7\left(90-\theta\right)\right)\right]^{0.38}}{0.740767}}_{\text{TNO/Shell Angle Correction}}$$

where

ρ_g = gas phase density, lbm/ft^3

ρ_L = liquid phase density, lbm/ft^3

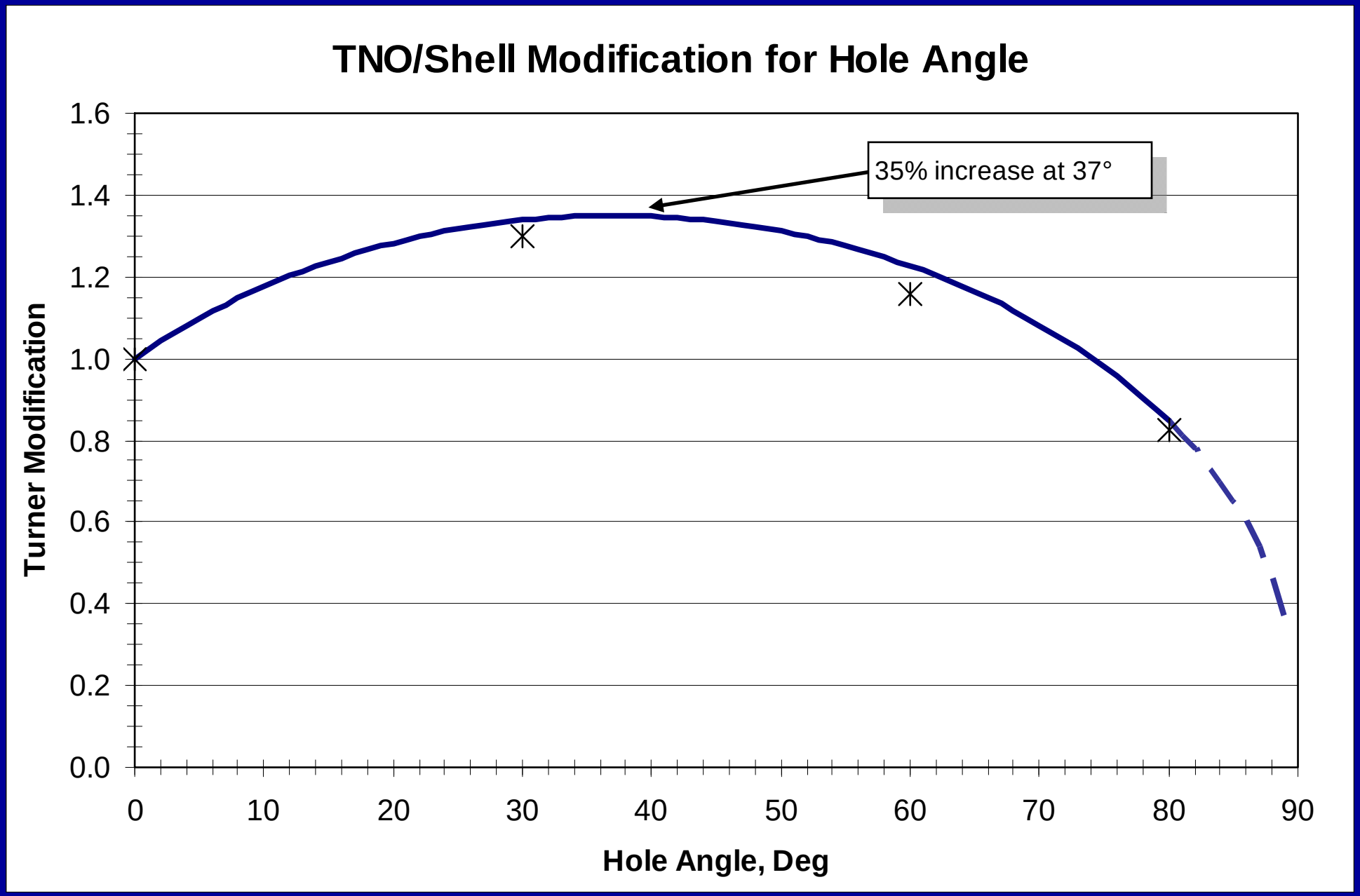
σ = surface tension, dynes/cm

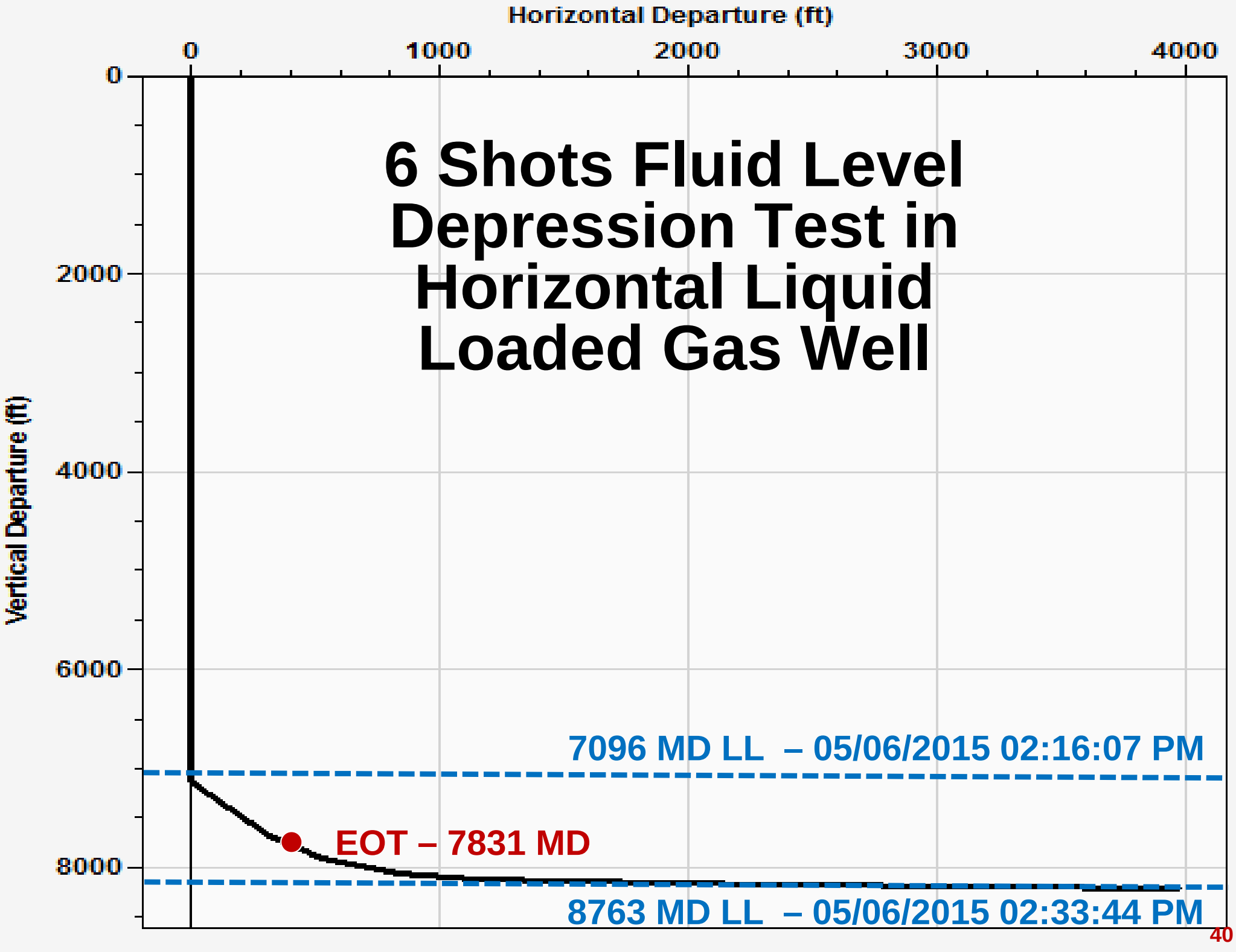
N_{we} = Weber Number (use 60 for original Turner)

Θ = hole angle (Deg from vertical)

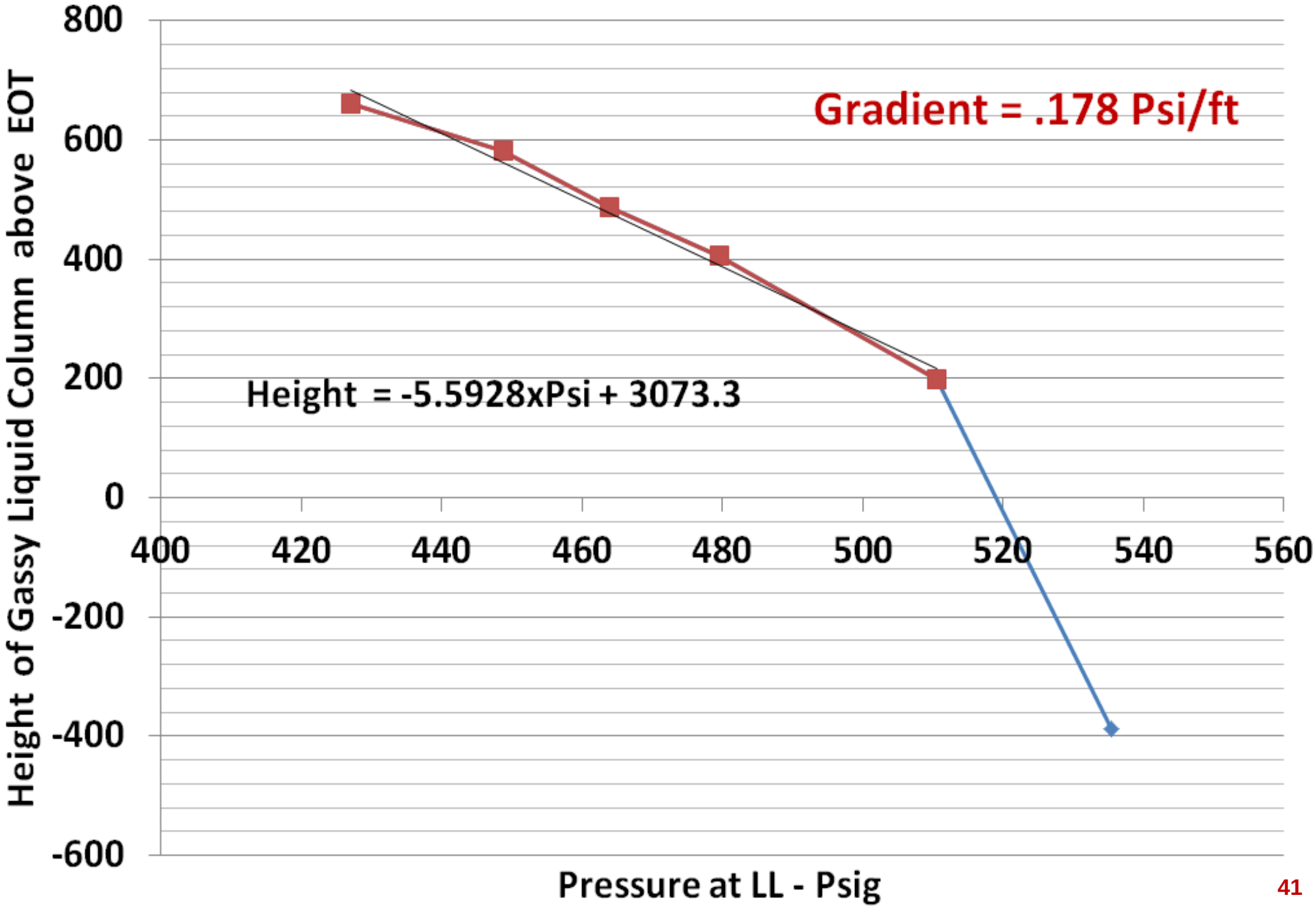
v_c = critical velocity of liquid droplet, ft/sec

Turner Angle Modification (TNO-Shell)




Horizontal Departure (ft)
0
1000
2000
3000
4000
Vertical Departure (ft)
0
2000
4000
6000
8000
6 Shots Fluid Level Depression Test in Horizontal Liquid Loaded Gas Well
7096 MD LL – 05/06/2015 02:16:07 PM
EOT – 7831 MD
8763 MD LL – 05/06/2015 02:33:44 PM

LL Depression Test in Liquid Loaded Horizontal Well



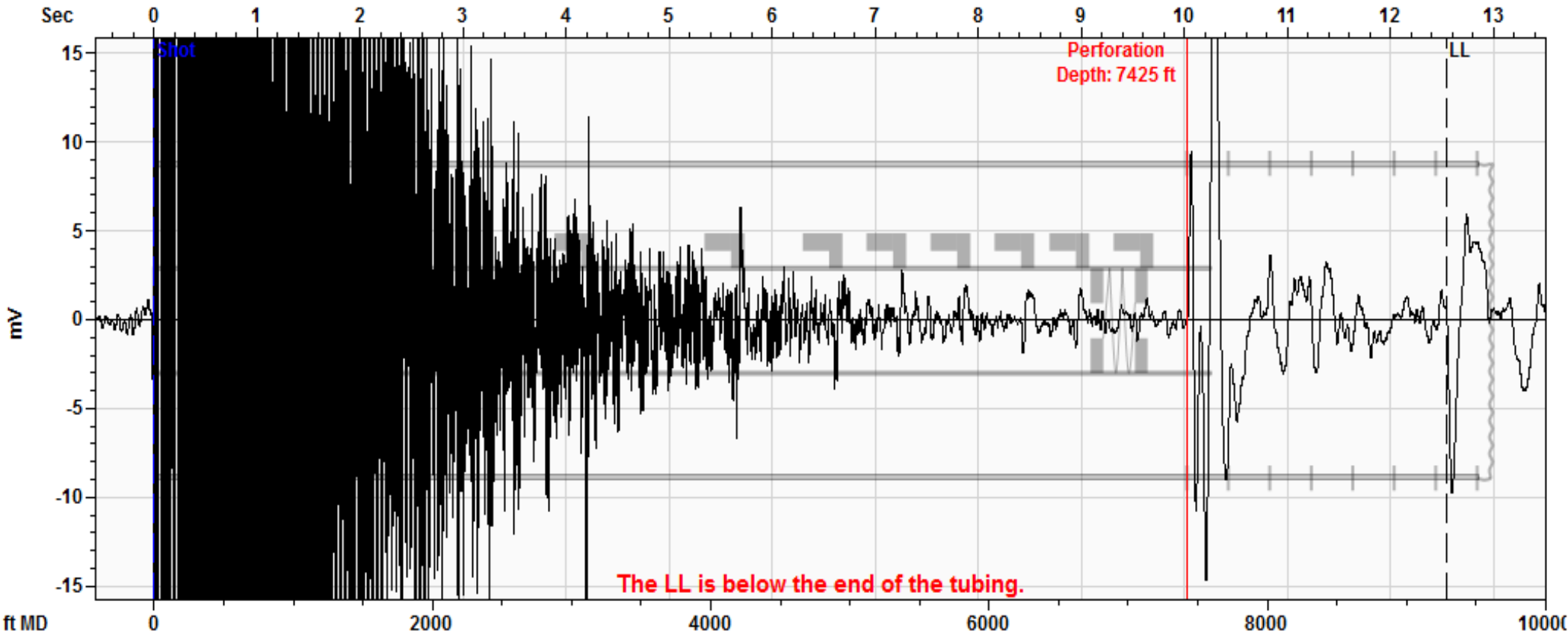
Liquid Loading below Kick-Off in Horizontal Well

- Example Horizontal Well is Liquid Loaded
- Shutting in well for 17 minutes, resulted in Liquid Load being Pushed Out of Tubing
- At End of Test the Liquid level was far Below EOT, Likely due to Stratified Flow in Horizontal Section
- Gradient in Tubing below Kick-off is 0.178 psi/ft, which is two (2) times higher than normal 0.08 psi/ft in a Vertical Gas Well

Stratified Gas Flow Regime Exist in Horizontal Gas Wells

1. Fluid level shot down the tubing/casing annulus shows a liquid level at a MD of 9287.
2. Being able to see past the end of the tubing is unusual in a vertical plunger lift well, because the liquid level is normally at the end of the tubing.
3. In horizontal wells stratified flow exists; it is not uncommon to see features in the well bore in the horizontal section past the end of the tubing.
4. Horizontal section appears to be relatively dry (no liquid level); but significant amount of liquid enters the tubing.
5. Differential tubing and casing pressure do not indicate much liquid loading, but liquid exist in horizontal and causes more liquid loading than expected (based on tubing & casing psi).

Overlay Wellbore Profile



Quick placement and verification of:

- Gas-lift valves and mandrels
- End of the Tubing
- Perforation Intervals

LL_Gas_Wells: PFL_Plunger_Horizontal_Mandrels

Horizontal Plunger Lifted Well

Well Conditions

Mechanical Wellbore

Lift System

Survey

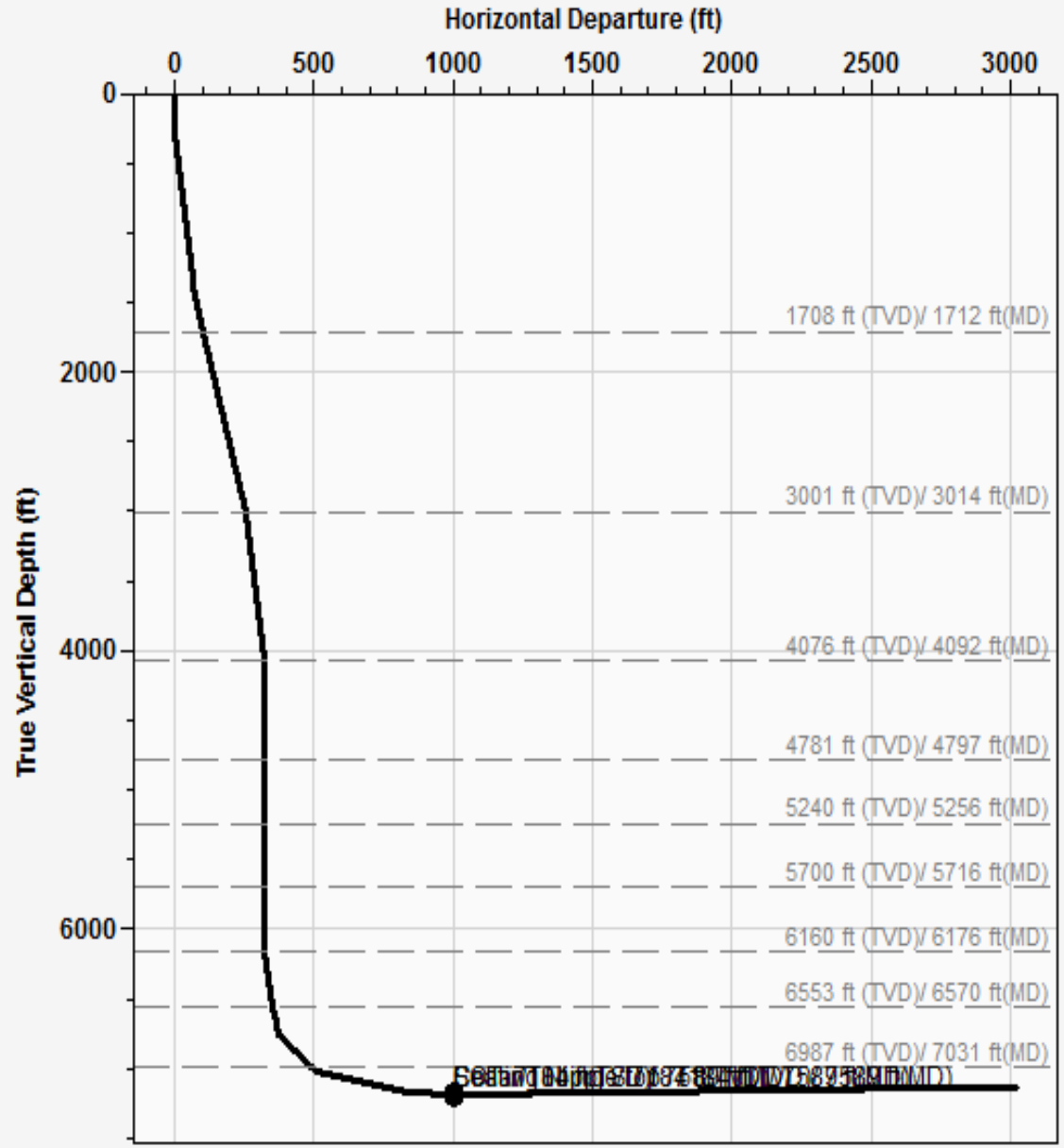
Producing Interval

Tubular Markers

Well Description

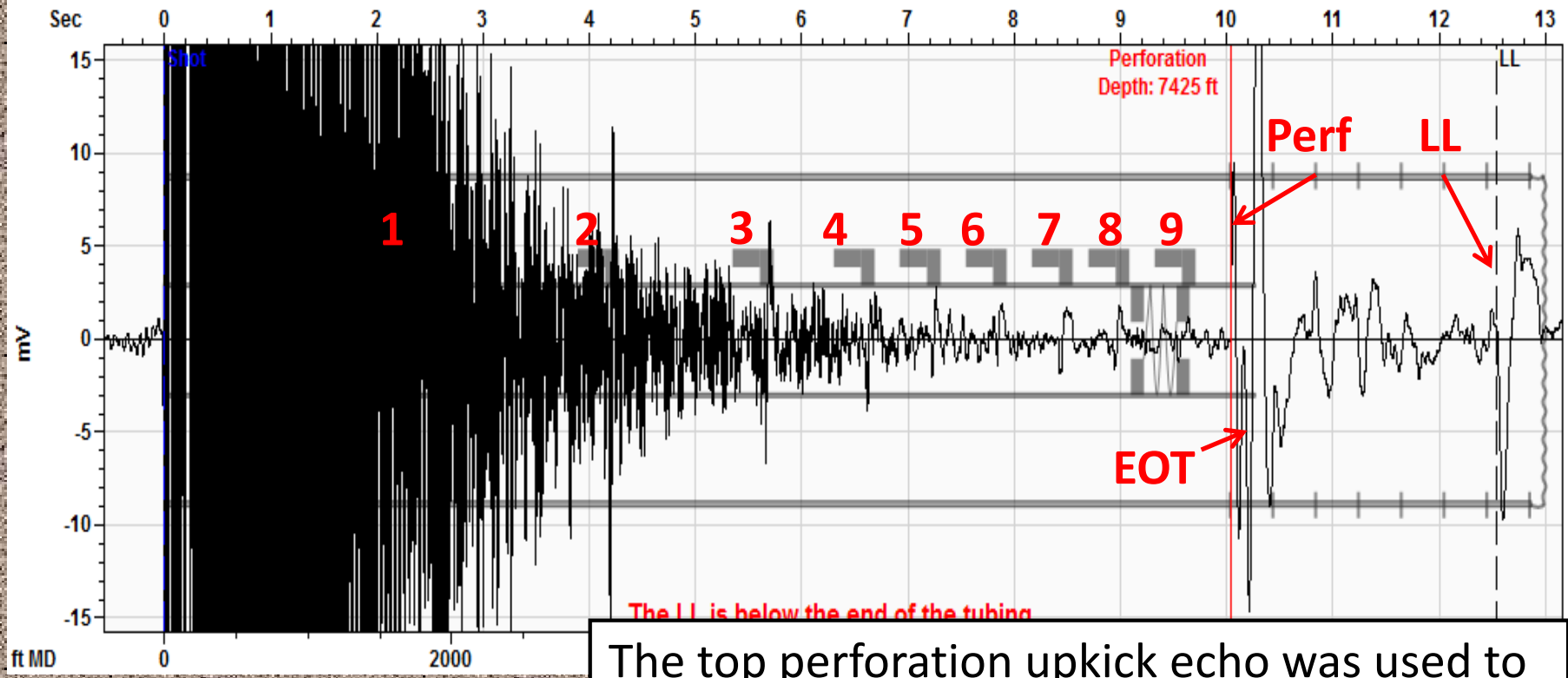
#	Measured Depth	True Vertical Depth
	ft	ft
1	278.00	278.00
2	1323.00	1321.00
3	1324.00	1322.00
4	1370.00	1368.00
5	1372.00	1370.00
6	1390.00	1388.00
7	1712.00	1708.00
8	1716.00	1712.00
9	3014.00	3001.00
10	3019.00	3005.00
11	4092.00	4076.00
12	4096.00	4080.00
13	4797.00	4781.00
14	4801.00	4785.00

Add Row | Insert Row | Delete Row



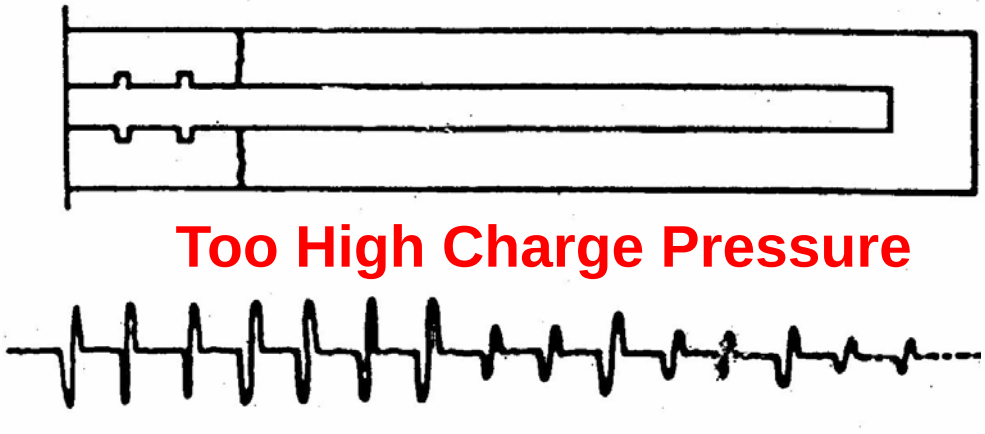
Change Template... | Summary | Undo | Save | Close

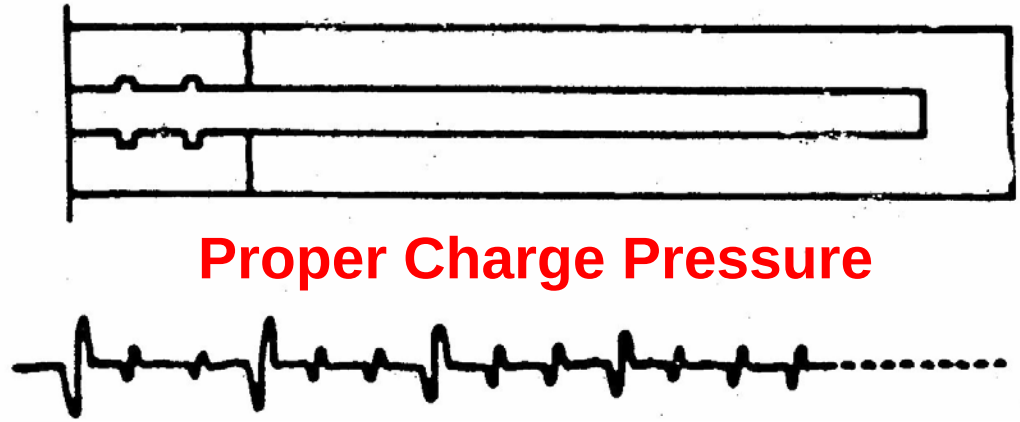
Reflections can be identified to the Toe Due to Stratified Gas Flow in the Horizontal section of the well.



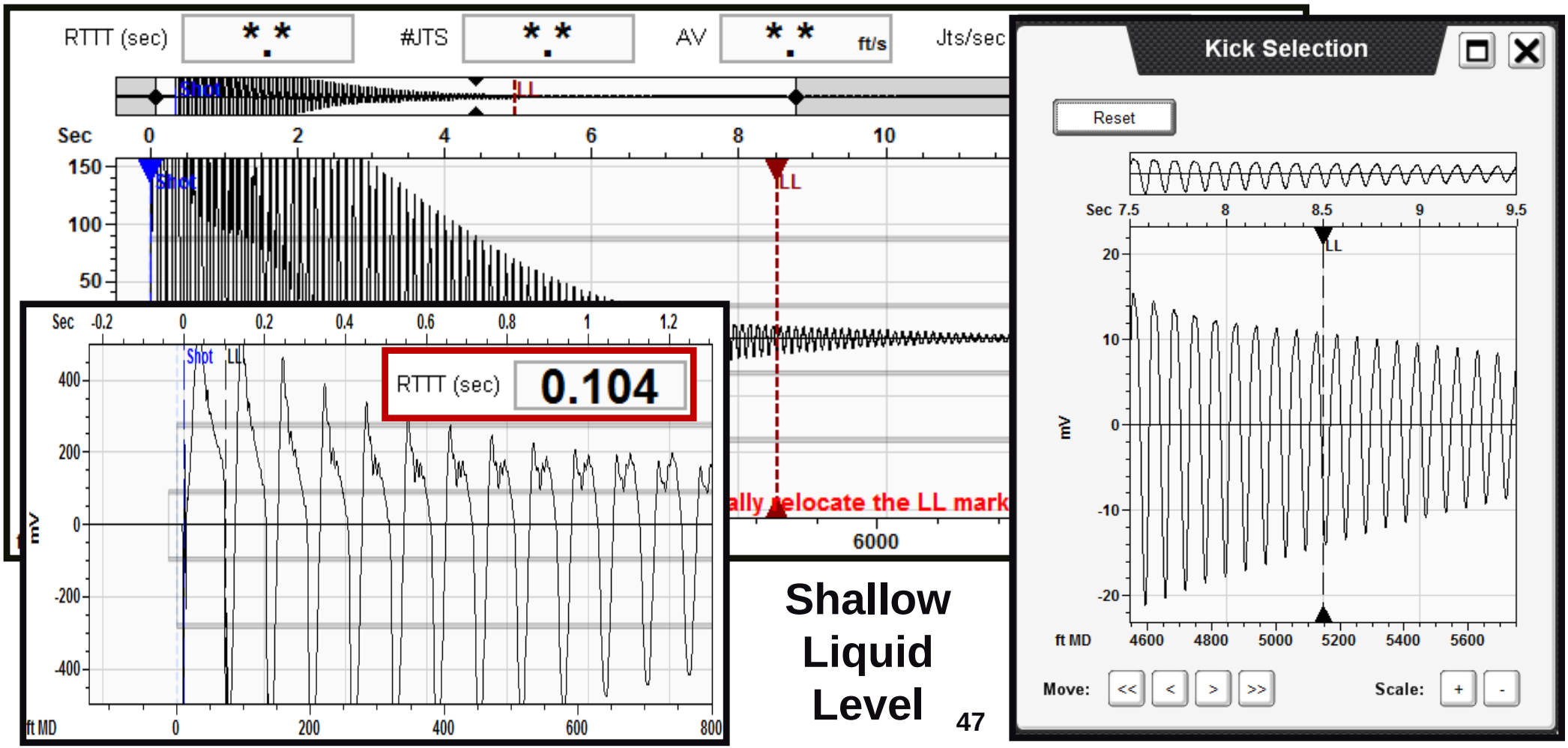
The top perforation upkick echo was used to determine the depths in the well.

PFL_Plunger_Horizonal_Mandrels





LL_Gas_Wells: PFL_Very_High

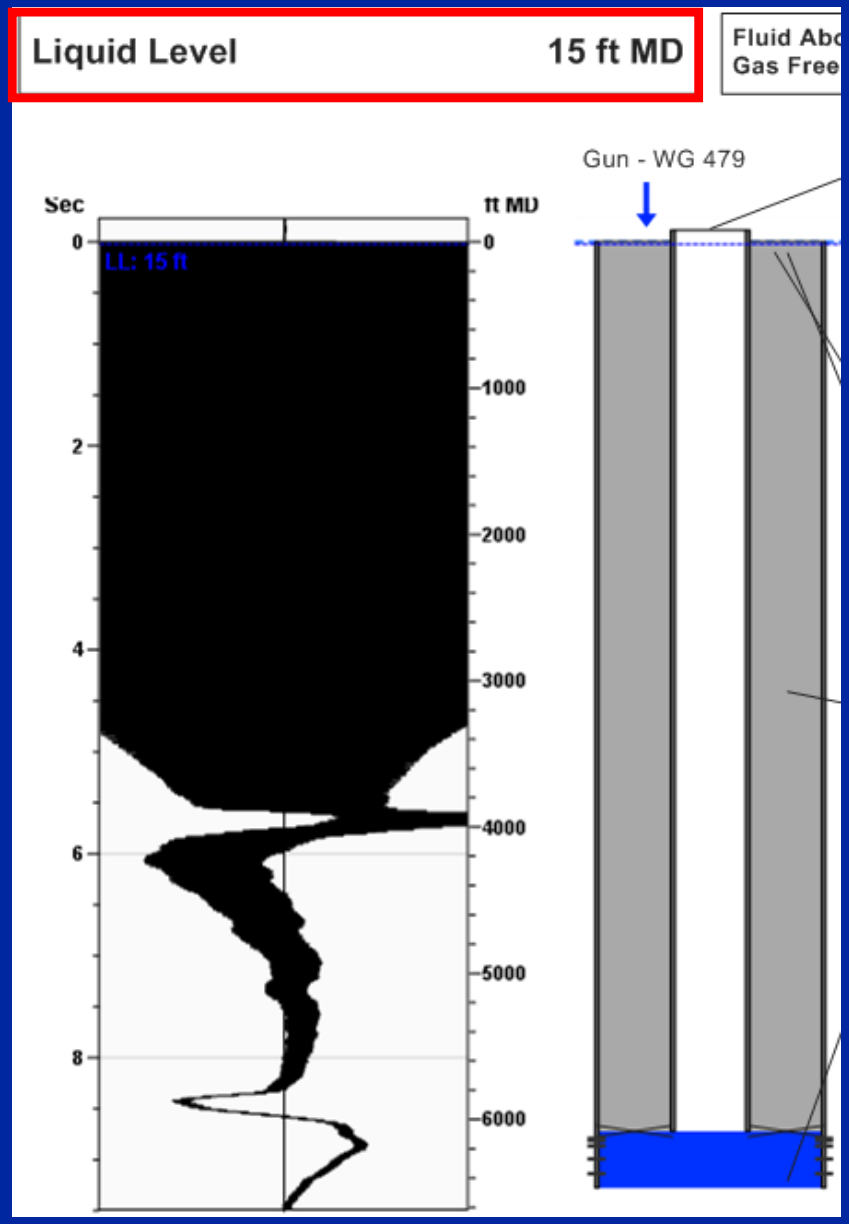


Shallow Liquid Level

Packer Integrity Testing w/ Acoustic Instrument

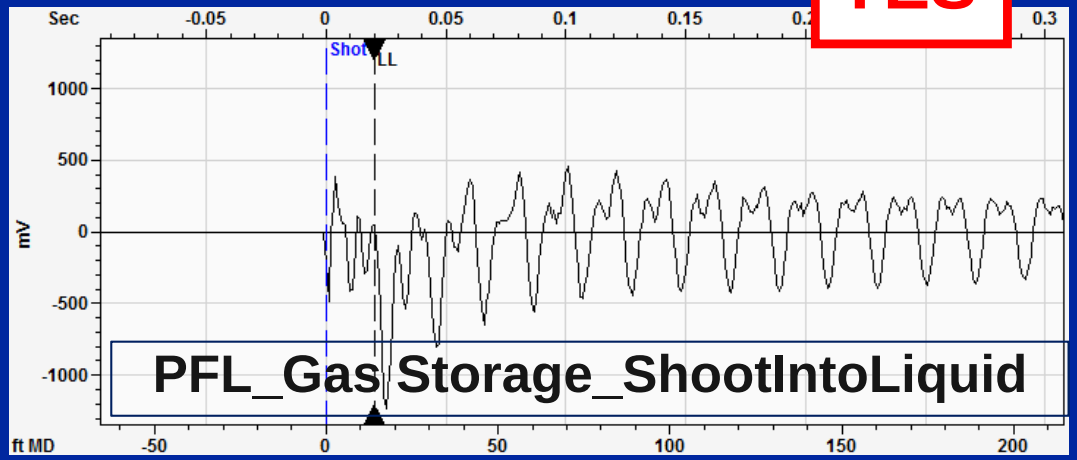
1. Identify Wells w/ Increased Annulus Pressure
2. DO NOT BLEED OFF PRESSURE
3. Acquire 2 shots on both Tubing and Annulus thru Fully Opening Valve
4. Shoot Fluid Levels on Tubing
   a) Calculate Pressure at Packer
5. Connect Acoustic Instrument to Annulus and Shoot Fluid Level
   a) Determine distance to Liquid Level
   b) Calculate Pressure at Packer
6. Bleed off Annulus Pressure and Shoot Fluid Level to Determine Gas Leakage Rate

Very High Fluid Level in Annulus Difficult

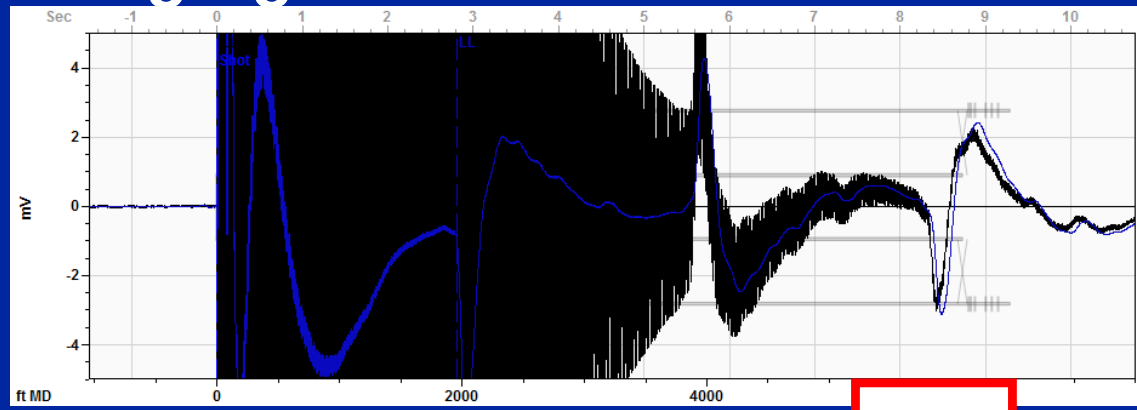


Fluid Level = 0.021 Sec

YES

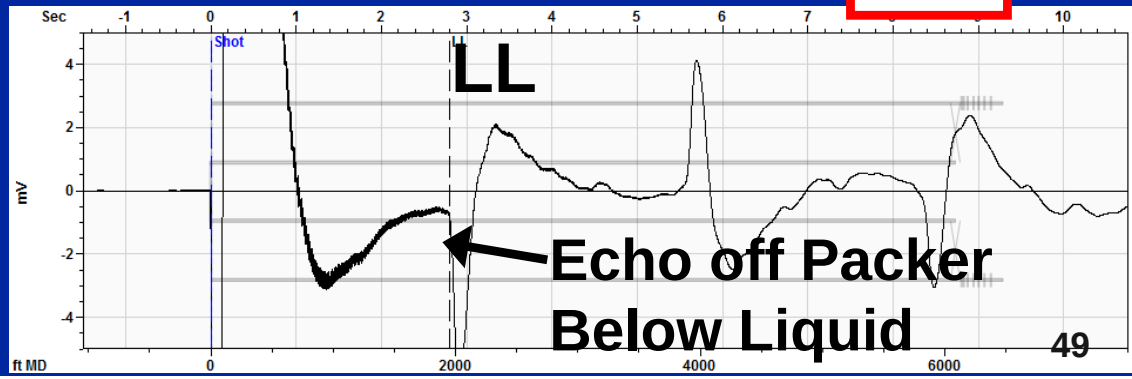


Ringing on Acoustic 0-8 Sec.



Fluid Level = 2.799 Sec?

NO

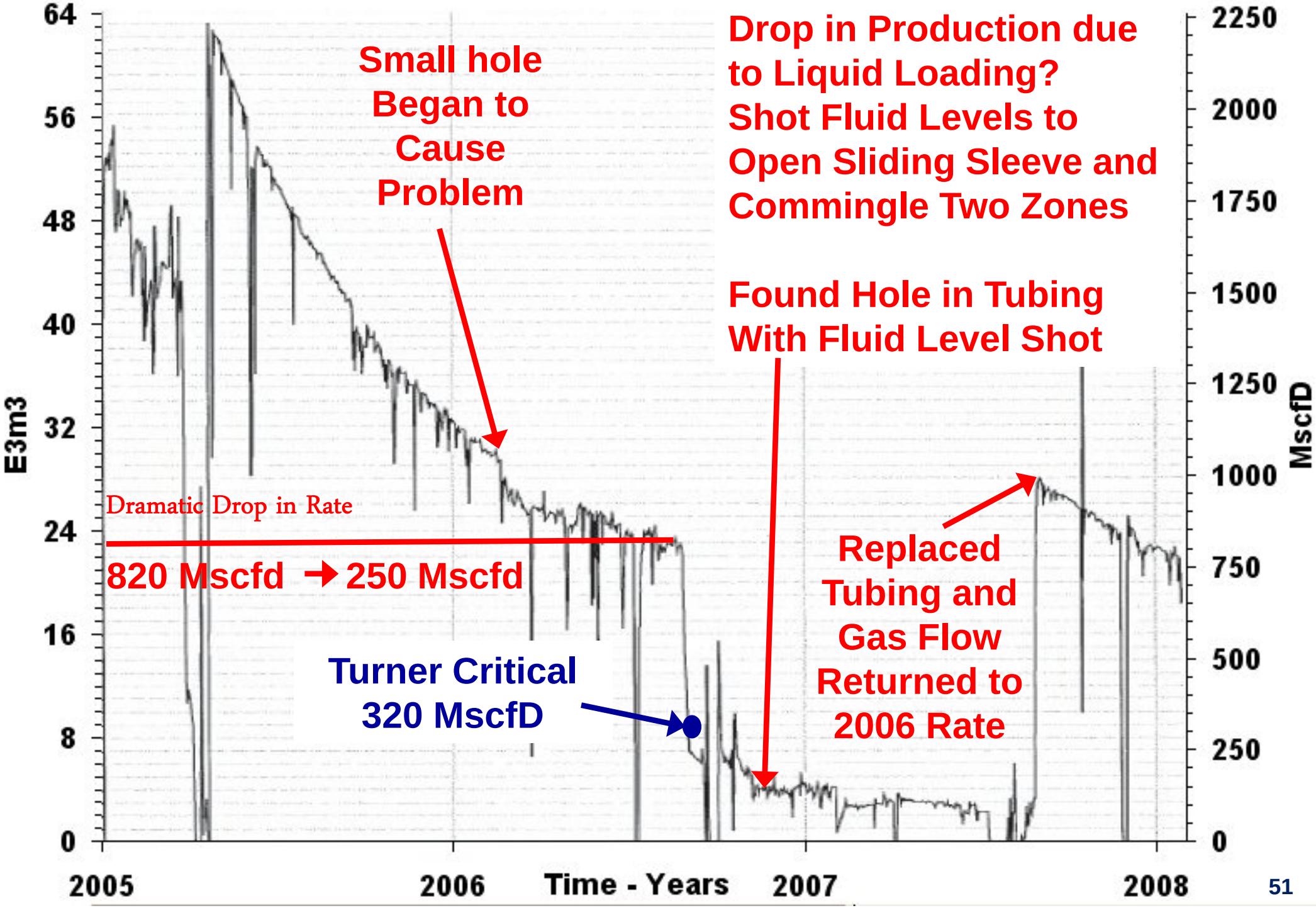


1. Kick @ 2.799 sec looks like LL
2. 4300 ft/sec AV Packer Fluid
3. 1391 ft/sec AV annulus gas

What If Casing Liquid Level Not at End of Tubing

- Acoustic Trace may not be Correctly Analyzed
- Too Many Perfs OR Not Enough Energy in Shot
- Gas May be Flowing up Casing Annulus
  1. Cross Flow into Another Perforated Interval
  2. Surface Casing Valve Leaking
  3. Flowing into Hole and up Tubing
- When Gas Well Flowing Up Tubing; High Fluid Level in Casing Usually is a Hole in the Tubing
- Shut-in Flow Depress Liquid Level Until Acoustic Traces Show Up Kick on Casing and Tubing Shots at Same Depth (From Hole)

Gas Well Production Curve - Flow Rate



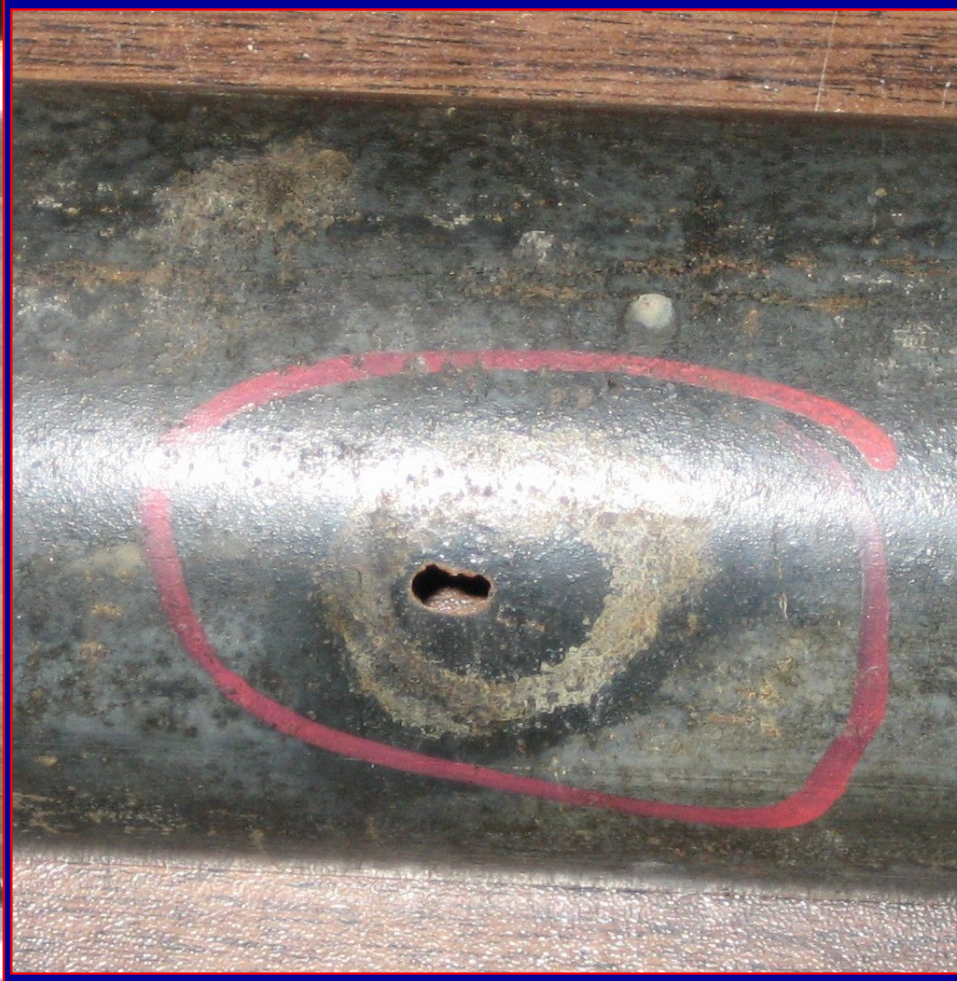
Use an Acoustic Fluid Level Instrument To Identify The Depth To The Hole

1) You must Shoot down both tubing and tubing/casing annulus
2) Shoot tubing/casing annulus while well is flowing up tubing (the Fluid Level should be near tubing intake or below perforations (If no Hole))
3) If you see a upkick that is not the perfs OR if you see a high fluid level in the tubing/casing annulus, then shut-in the well, continue to shoot casing annulus looking for down kick due to liquid leaking from hole in tubing back into annulus.
4) Increasing Pressure pushes liquid down, and after shooting fluid levels for a while the high casing fluid level should be pushed deeper into the well and the hole should be uncovered.
5) After 1-2 hours of shooting tubing and casing annulus an upkick from hole should be seen at the same depth on both shot down tubing and shots down casing.
6) OR shut-in well over night, then come back in morning to shoot well when pressure is high and fairly easily see upkick from the holes….

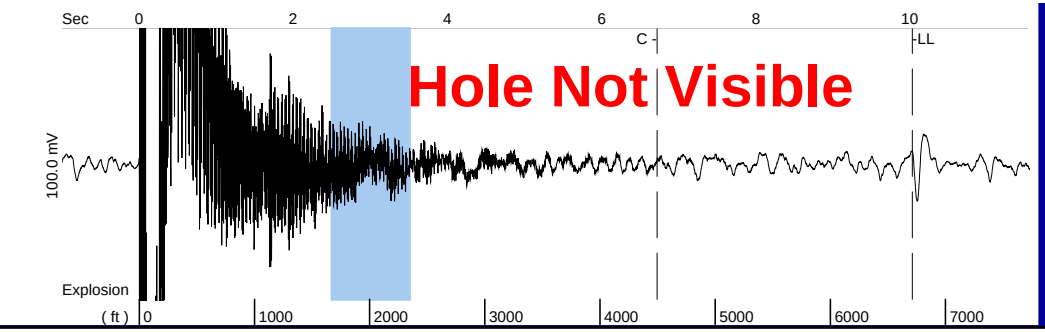
Can’t be a Hole ~ Tubing is New

Hole @ Depth 4325 Ft from Surface

Inside Pipe

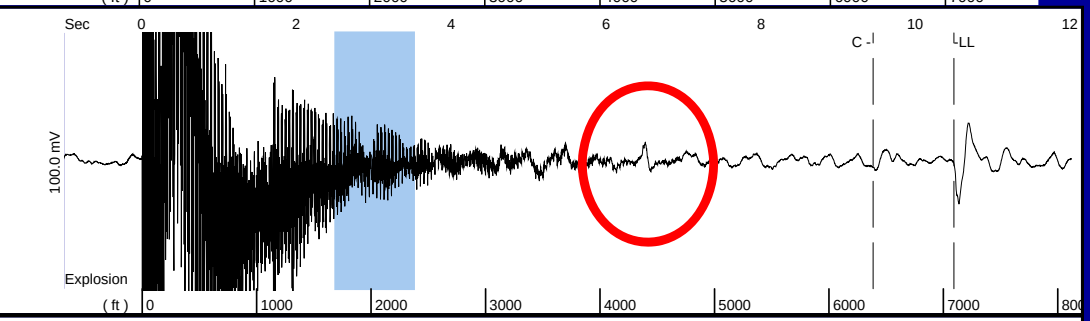


Outside Pipe

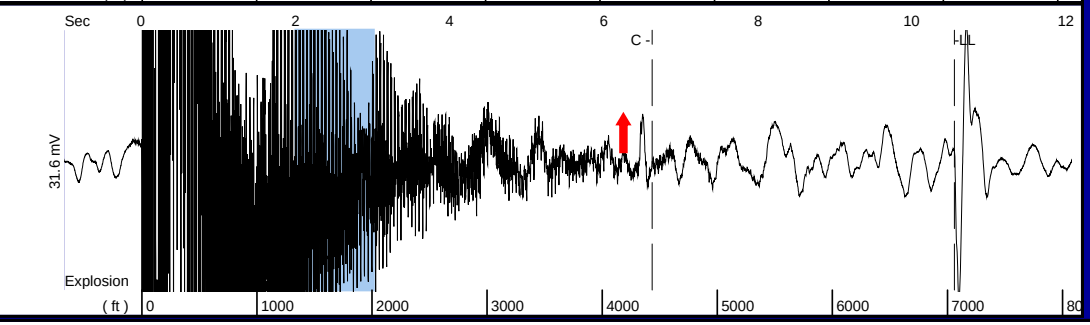


Time 12:12:27 Csg 125.9 Psi

Shot Casing/ Flowing Up Tubing

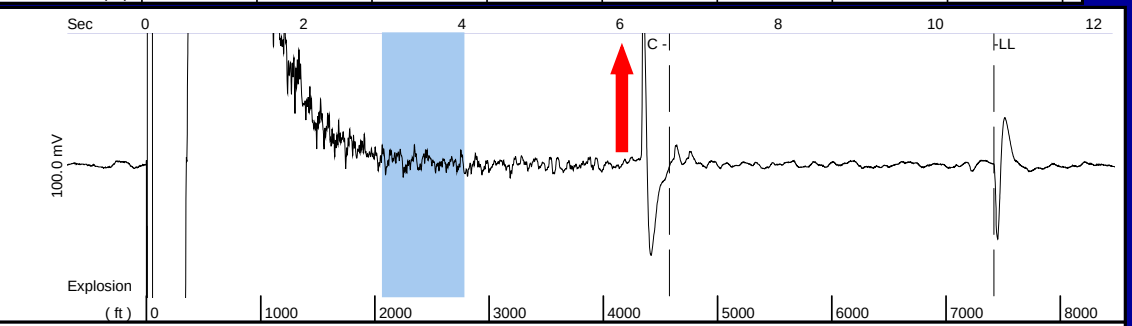


Time 12:24:15 Csg 135.5 Psi
Shot Casing/ Tubing Flow Shut-in

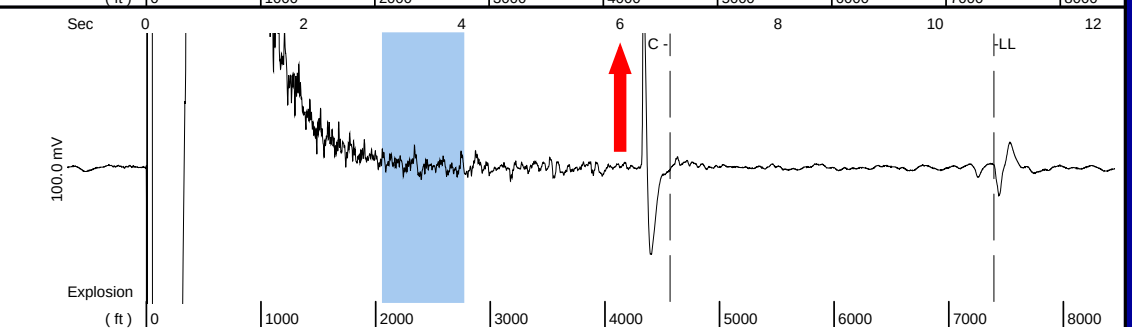


Time 12:29:14 Csg 138.8 Psi

Shot Casing/ Tubing Flow Shut-in



Time 12:35:58 Tbg 143.1 Psi
Shot Tubing/ Flow Shut-in



Time 13:09:38 Tbg 150.8 Psi
Shot Tubing/ Flow Shut-in

Plunger_Hole_4325

Holes in Tubing

- DO NOT be surprised if more than 10% of your liquid loaded gas wells have holes in the tubing.
- Hole Causes Significant Drop in Gas Production.
- Tubing and Casing Pressure are Not Equal with Hole
- When flow up tubing; High Fluid Level in Casing Likely Indicates a Hole in the Tubing
- High Cost of using a wire-line to set a standing valve and pressure test the tubing may be avoided
- Using an acoustic fluid level instrument is a low cost, quick method to troubleshoot a gas well and to identify the presence/location of a hole.

Verified SSSV is Functioning

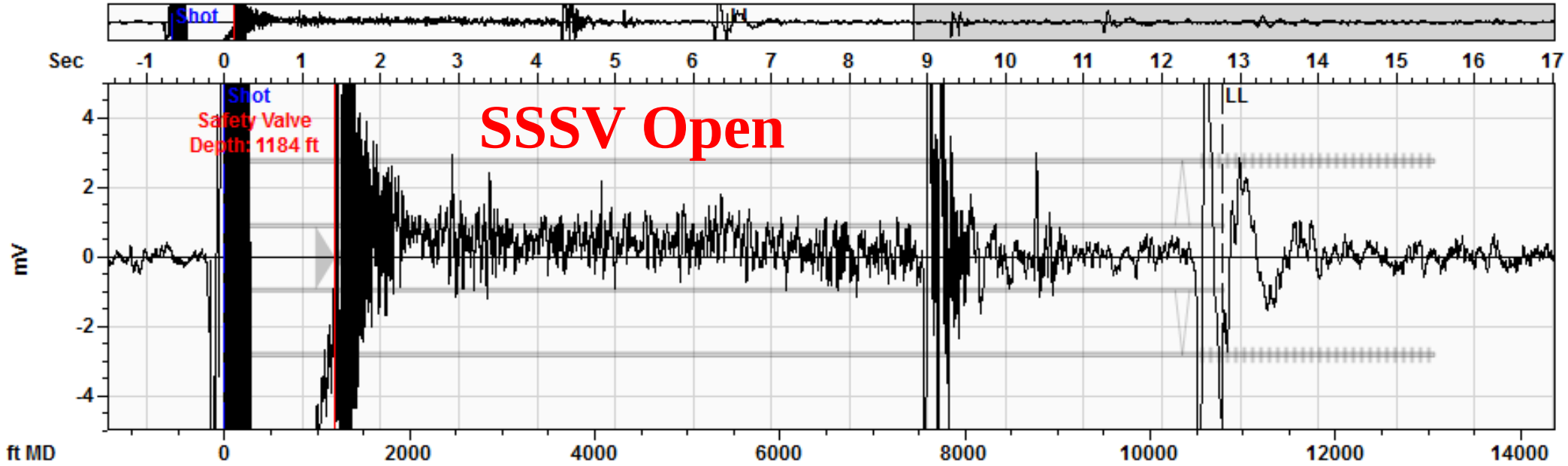
PFL_SSSV

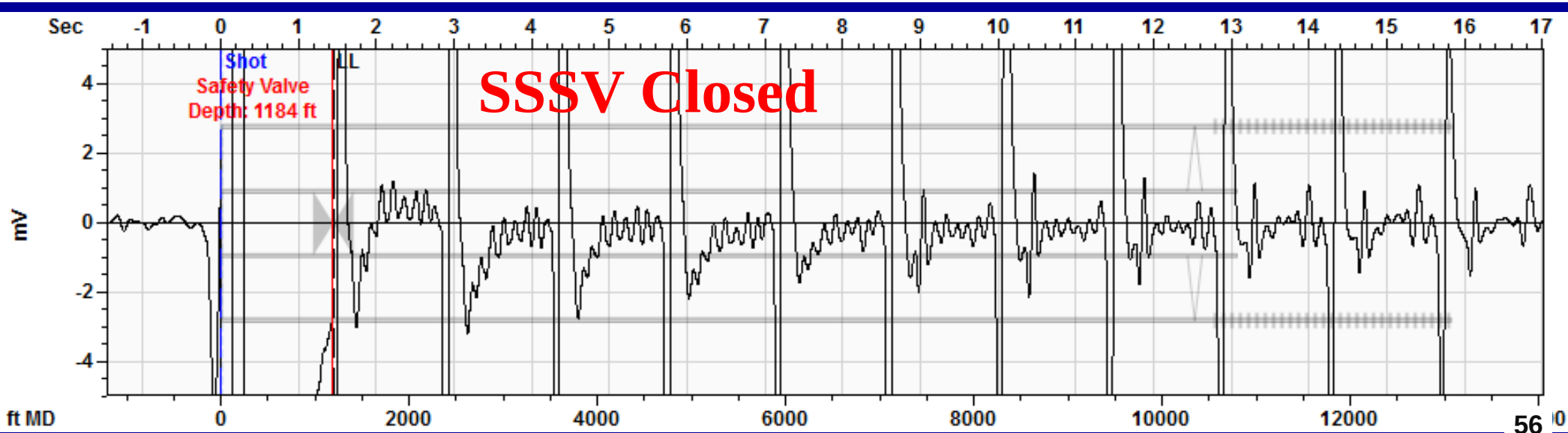
Distance To Liquid **10770** ft MD

Fluid Above Tubing **2** ft TVD

Equivalent Gas Free Above Tubing **2** ft TVD

RTTT (sec) **12.762** #JTS **339.75** AV **1688** ft/s Jts/sec **26.62**





Type of Survey	Current Process	Advantage
Determine liquid Level and BHP in Liquid Loaded Gas Well	Flowing Pressure Gradients on Slickline	Save Day(s) of Wireline, crew, and equipment
Flowing Gaseous Column Gradient	Flowing Pressure Gradients on Slickline	Save Day(s) of Wireline, crew, and equipment
Static BHP and Liquid Level	Static Pressure Gradients on Slickline	Save Day(s) of Wireline, crew, and equipment
Static Fluid Level ~ Maximum tubing set Depth	Slickline / not done	Save Day(s) of Wireline, crew, and equipment
Liquid Level in Annulus	Calculations based on N2 Injected	More Accurate Information
Integrity Testing of Annulus	Calculations based on N2 Injected	Determine Gas Leak Rate
Locate Holes in Tubing/Casing	Slick Line set SV and Pressure test	Save Day(s) of Wireline, crew, and equipment
Monitor Effectiveness of Batch Treatment	Not previously possible	Increase Production Rate
Track fall rate of plunger, batch corrosion and foam jobs	Slickline/Not possible	Save Day(s) of Wireline, crew, and equipment
Gain understanding of liquid loaded well behavior	Not previously possible	Increase Production Rate
Confirm SSSV Close/Open Operation	Slickline	Save Day(s) of Wireline, crew, and equipment