



Gas Well Deliquification Workshop

Sheraton Downtown Denver Hotel

Denver, Colorado

February 20 - 22, 2012

Introduction to Plunger Lift

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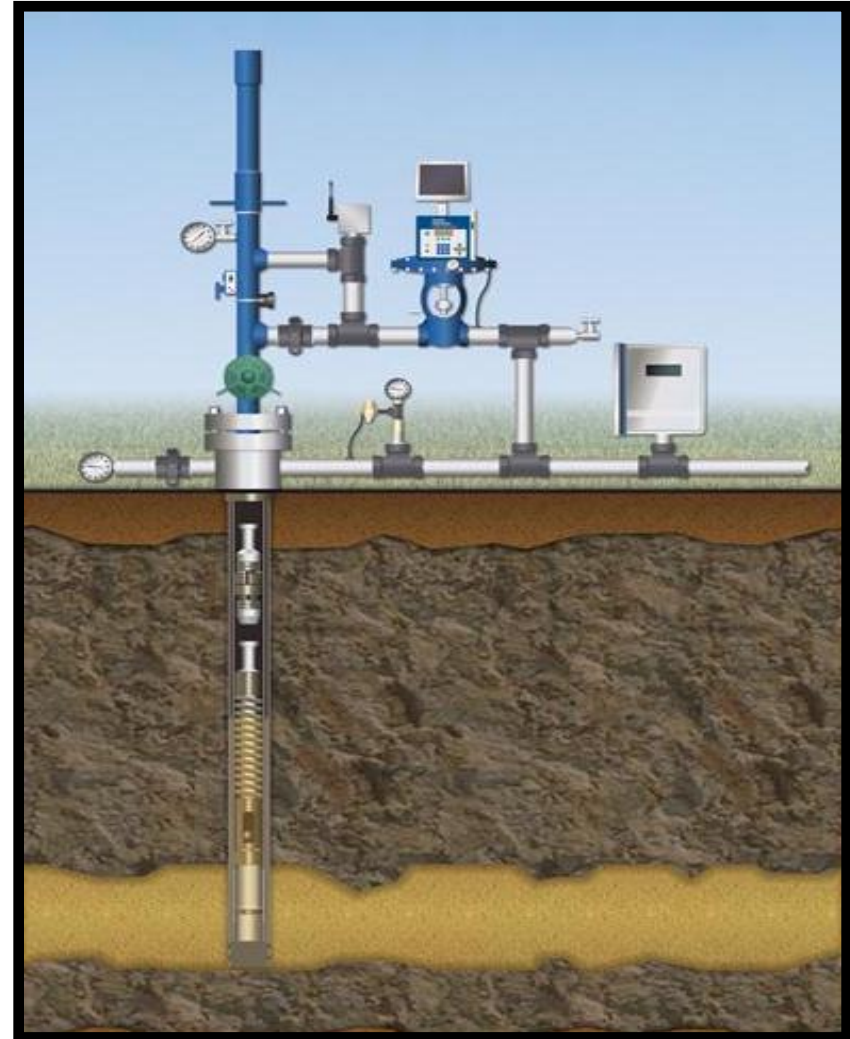
Ferguson Beauregard

Introduction to Plunger Lift

- ❑ How does plunger lift work
- ❑ Why is artificial lift required
- ❑ When is plunger lift needed
- ❑ Benefits, limitations, economics
- ❑ Key components
- ❑ Optimizing and Troubleshooting
- ❑ Safety

PRIMARY PURPOSE

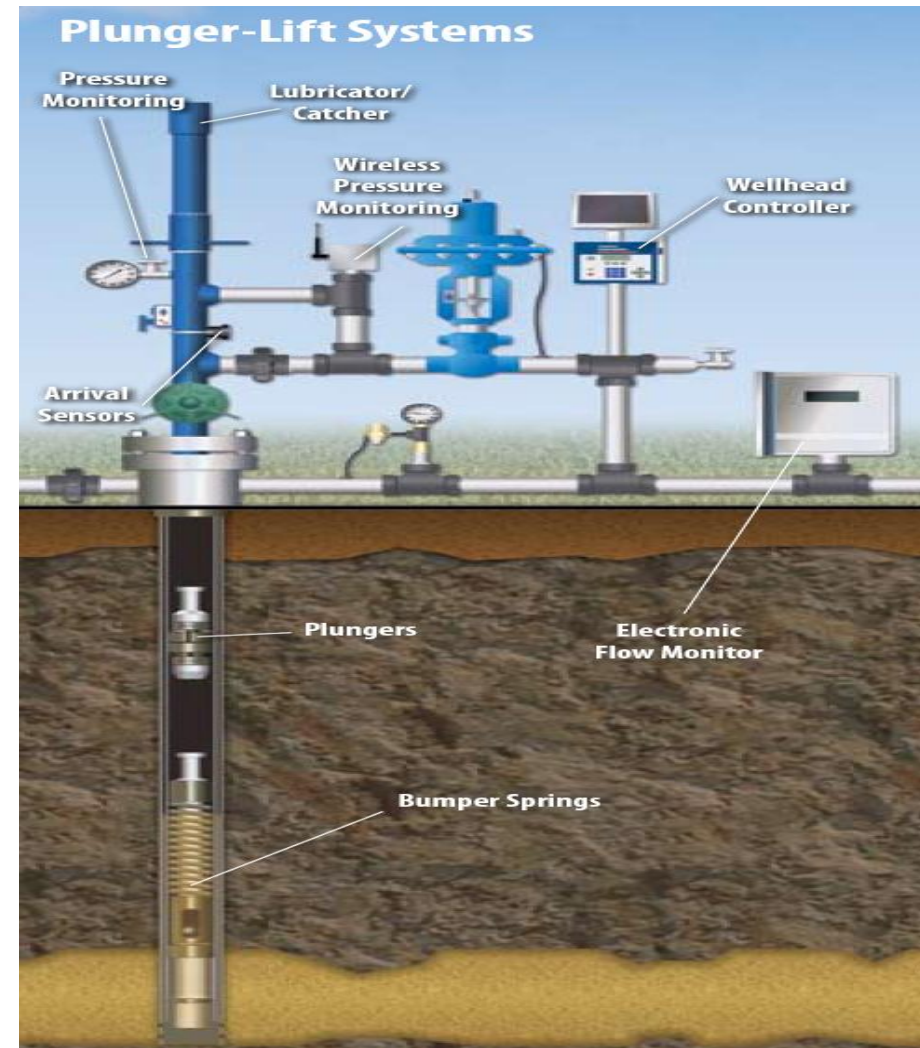
Remove liquid from a well so that gas can flow freely to the surface.



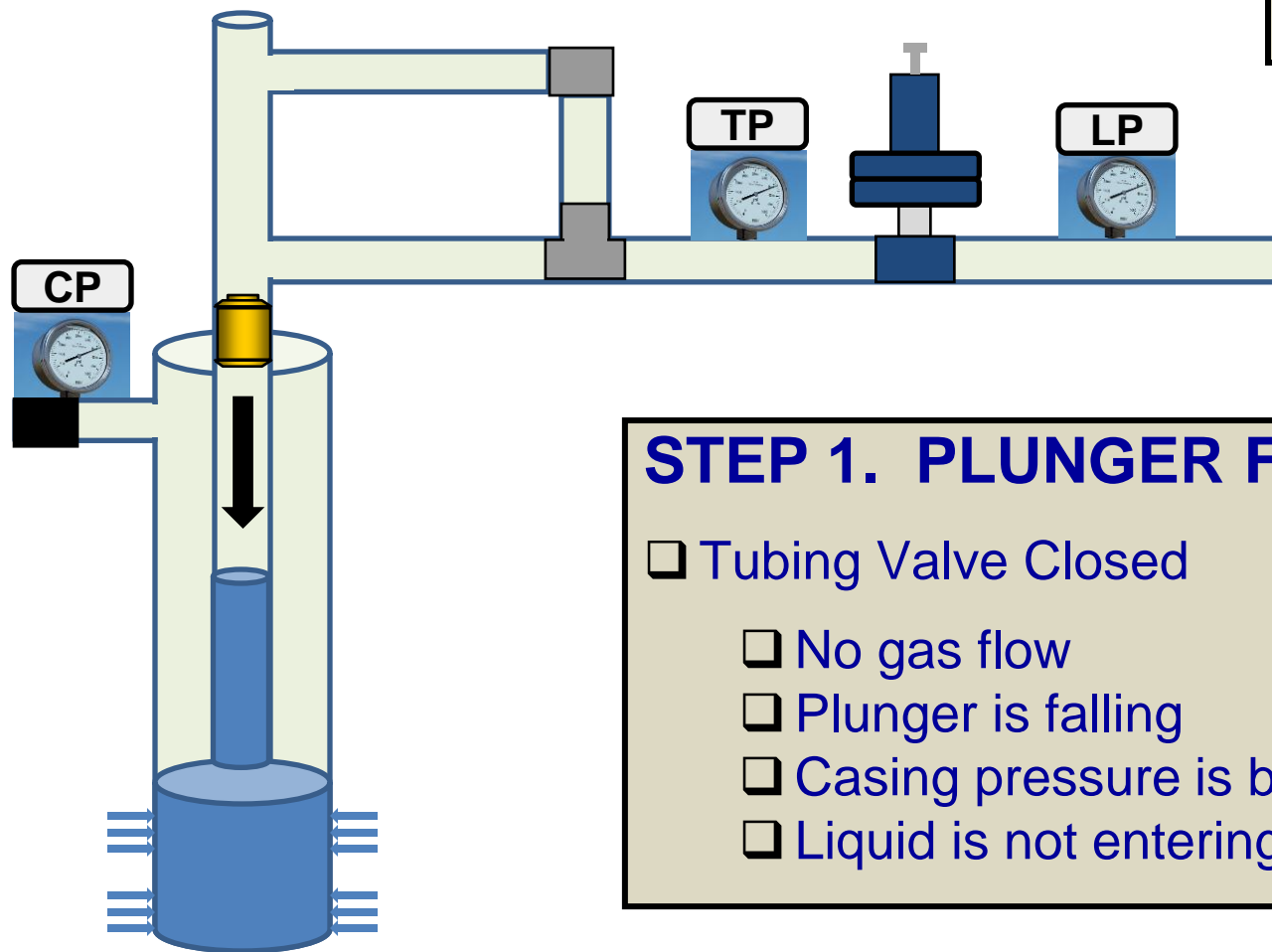
HOW DOES PLUNGER LIFT WORK

How Does Plunger Lift Work

- ❑ Bottom Hole Spring
- ❑ Plunger
- ❑ Arrival Sensor
- ❑ Lubricator / Catcher
- ❑ Pressure Transducers
- ❑ Motor Valve(s)
- ❑ Gas Flow Meter
- ❑ Well Head Controller



How Does Plunger Lift Work

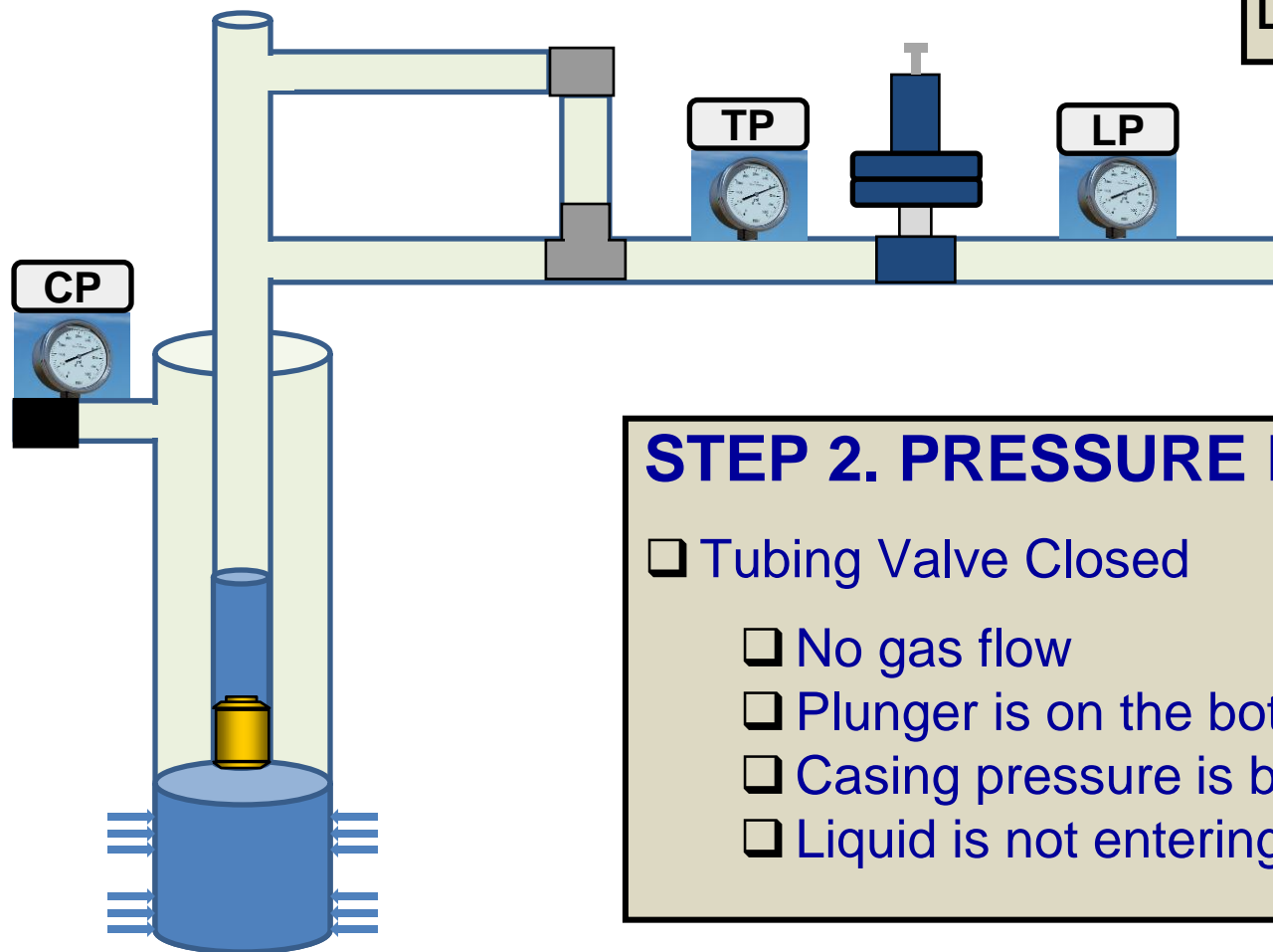


$$\text{LIQUID LOAD} = (\text{CP} - \text{TP})$$

STEP 1. PLUNGER FALL MODE

- Tubing Valve Closed
 - No gas flow
 - Plunger is falling
 - Casing pressure is building
 - Liquid is not entering tubing (most wells)

How Does Plunger Lift Work

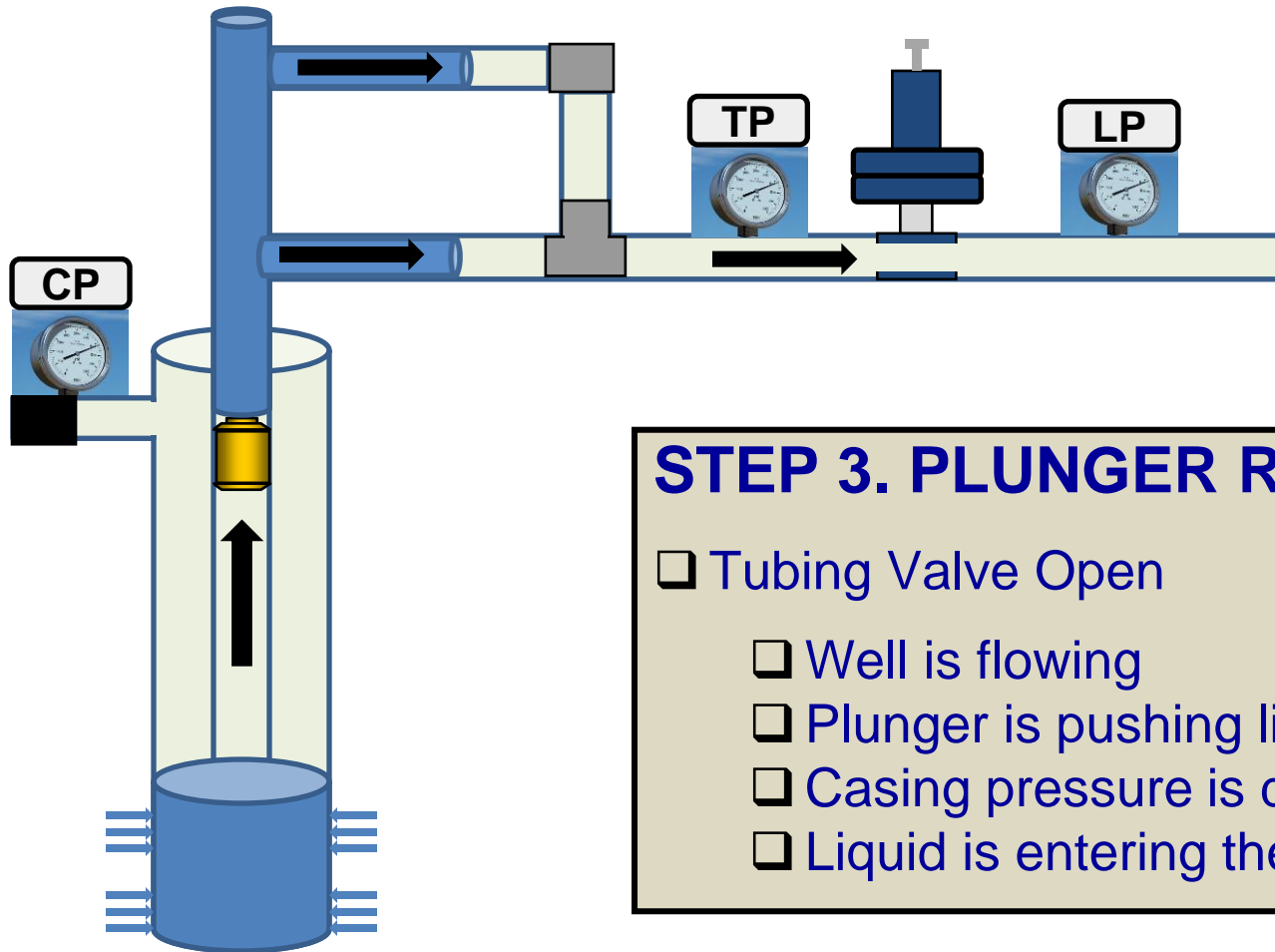


$$\text{LIFT PRESSURE} = (\text{CP} - \text{LP})$$

STEP 2. PRESSURE BUILD MODE

- Tubing Valve Closed
 - No gas flow
 - Plunger is on the bottom
 - Casing pressure is building
 - Liquid is not entering tubing (most wells)

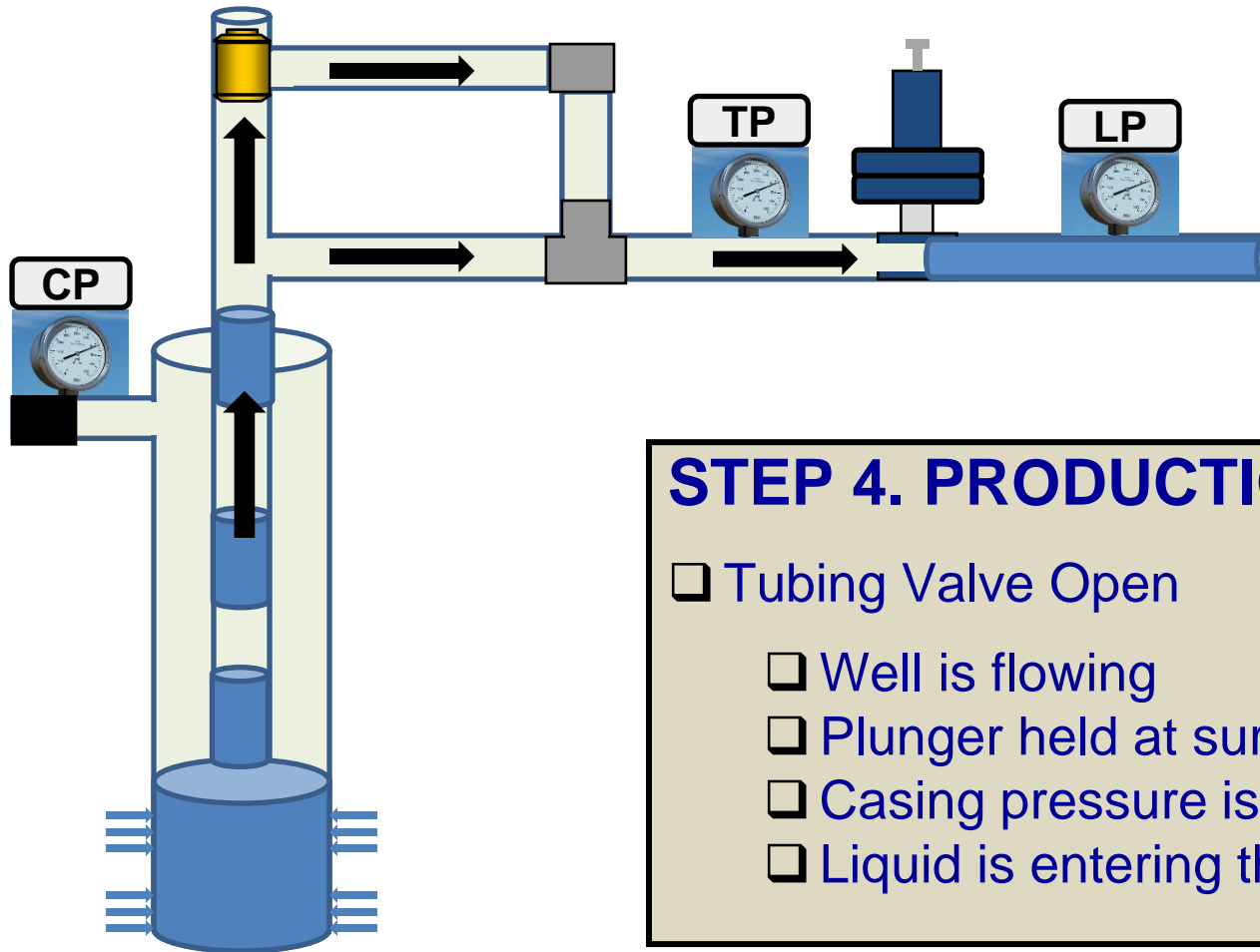
How Does Plunger Lift Work



STEP 3. PLUNGER RISE MODE

- Tubing Valve Open
 - Well is flowing
 - Plunger is pushing liquid to the surface
 - Casing pressure is declining
 - Liquid is entering the tubing

How Does Plunger Lift Work

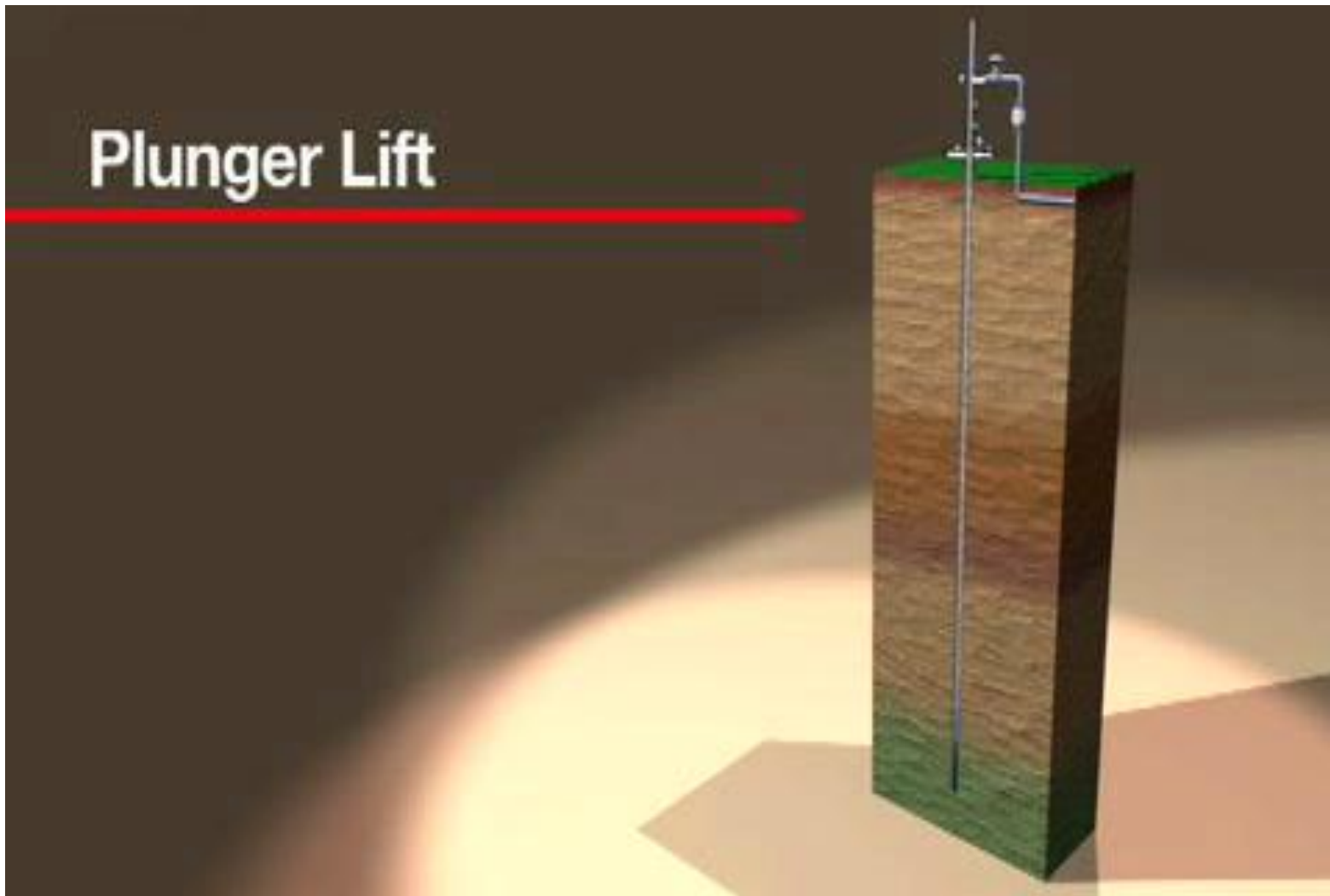


STEP 4. PRODUCTION MODE

- Tubing Valve Open
 - Well is flowing
 - Plunger held at surface by gas flow rate
 - Casing pressure is declining
 - Liquid is entering the tubing

How Does Plunger Lift Work

VIDEO



How Does Plunger Lift Work

DOWNWARD FORCE

Liquid Load (CP-TP)
Line Pressure
Restrictions

PLUNGER EFFICIENCY

Best – Brush or Pad
Worst – Bar Stock

UPWARD FORCE

Lift Pressure (CP – LP)



FAST



1000 fpm
GOOD
500 fpm



SLOW

Restrictions

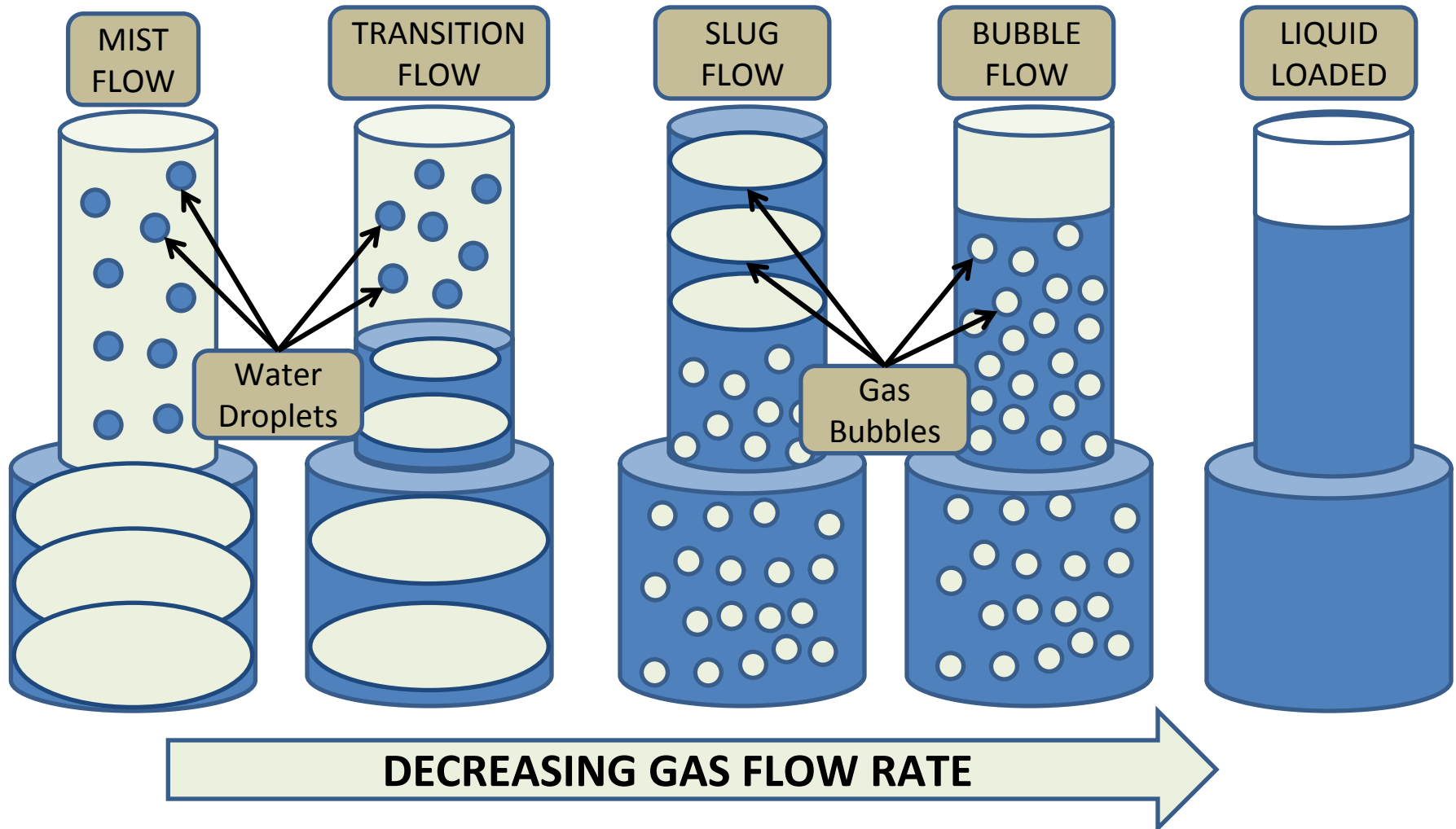
- Scale, Paraffin, Hydrates
- Sand
- Motor valve trim size
- Choke (even if open!)
- Hold down assembly
- Orifice plate

Lift Pressure \geq 2 X Liquid Load

RULE OF THUMB

WHY IS ARTIFICIAL LIFT REQUIRED

Why Is Artificial Lift Required



Why Is Artificial Lift Required

VIDEO



Why Is Artificial Lift Required

BACKPRESSURE

High Line Pressure

LIQUID LOADING

Scale / Paraffin Build-Up
Chokes

Motor Valve Trim Size

Multiple 90 degree elbows

Small Orifice Plates

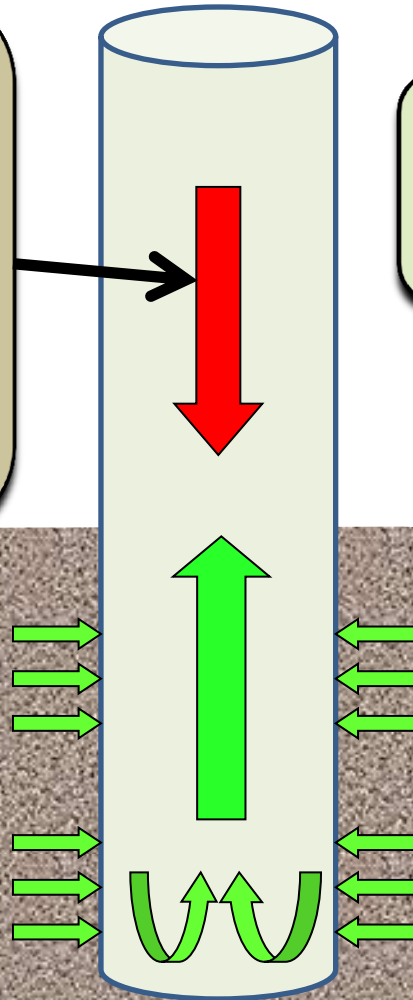
**FLOWING BOTTOM HOLE
PRESSURE**

HIGH = LESS PRODUCTION

LOW = MORE PRODUCTION

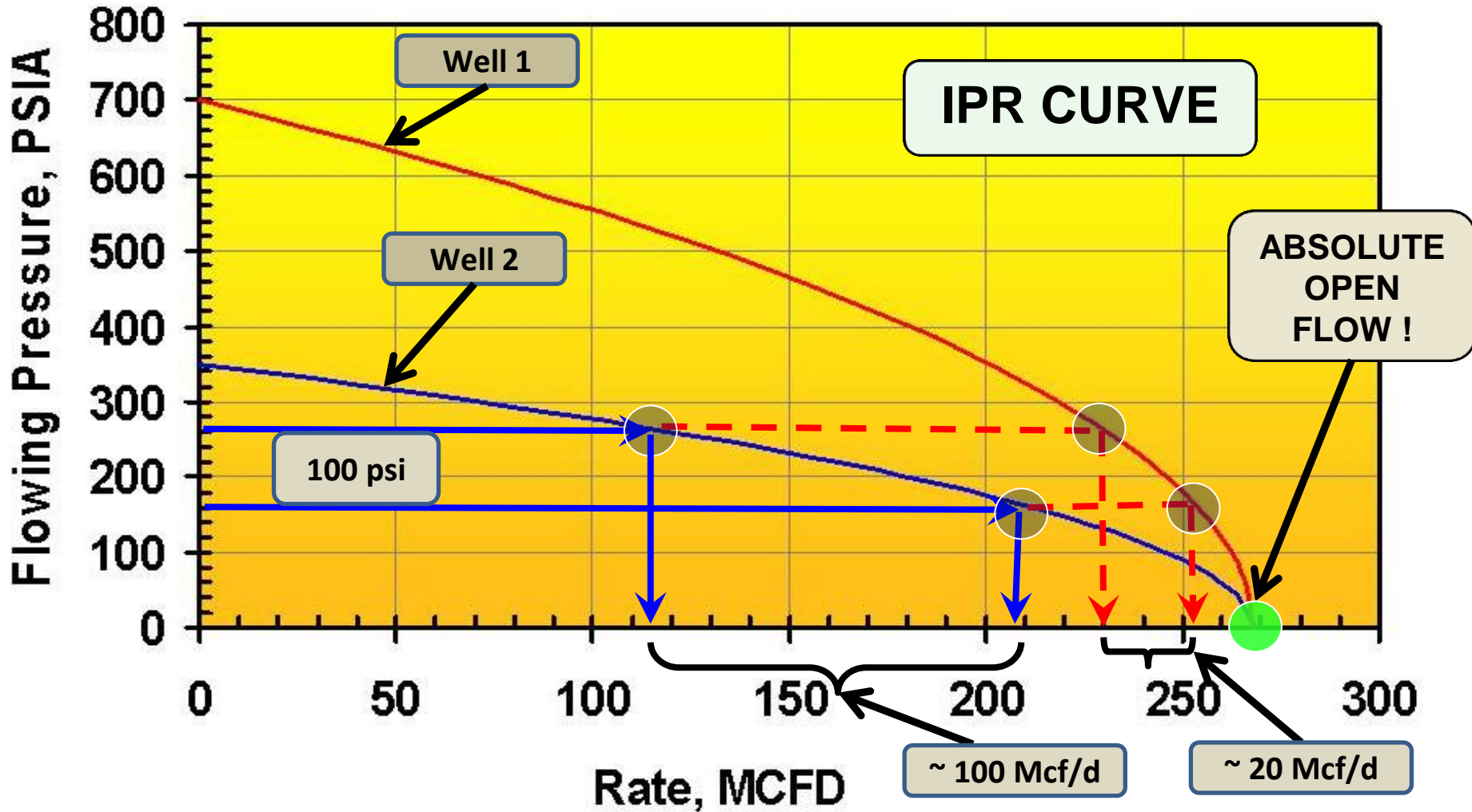
Over 90% of the gas wells
in the US are liquid loaded
(Marathon study)

**RESERVOIR
PRESSURE**

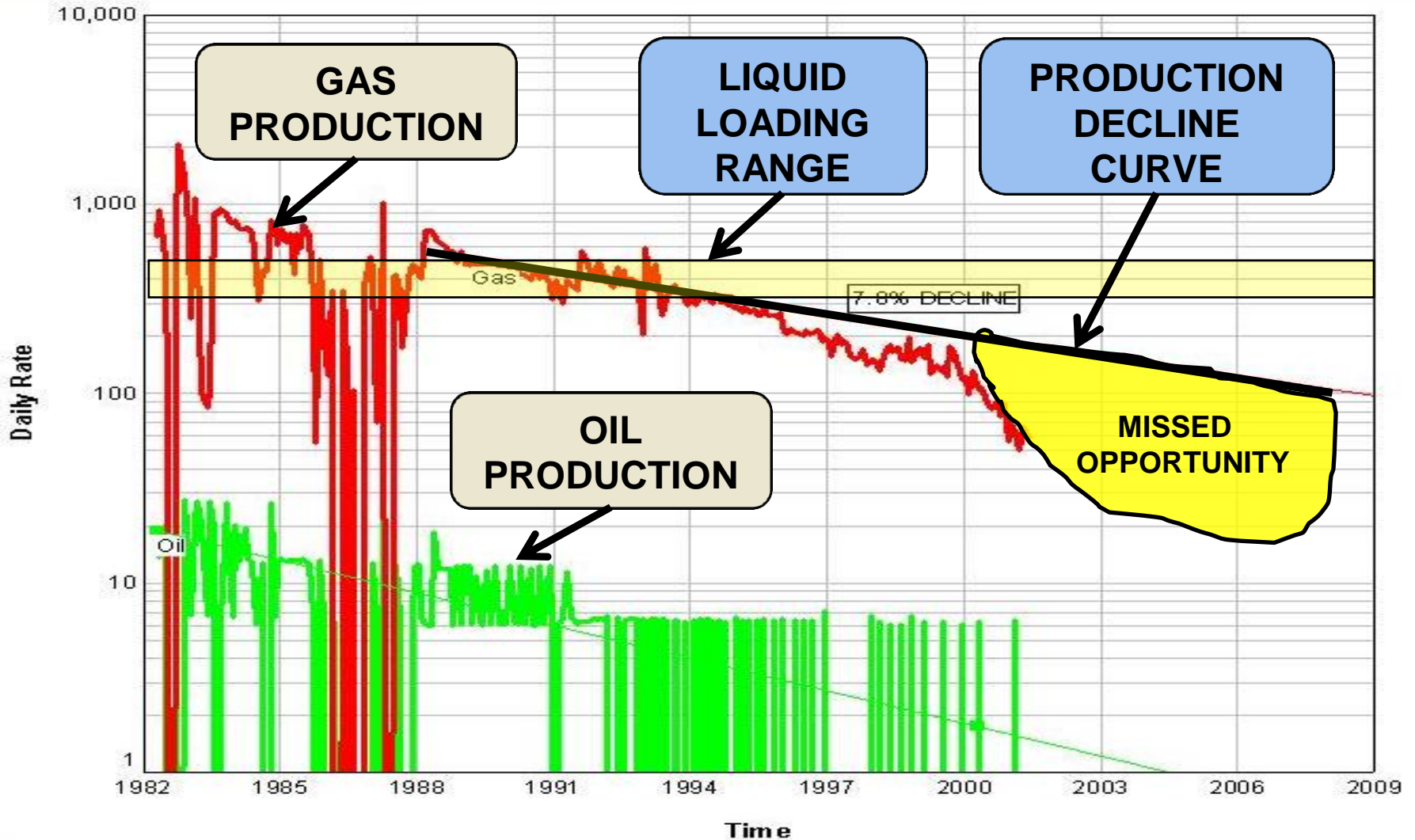


Why Is Artificial Lift Required

How Much More ?

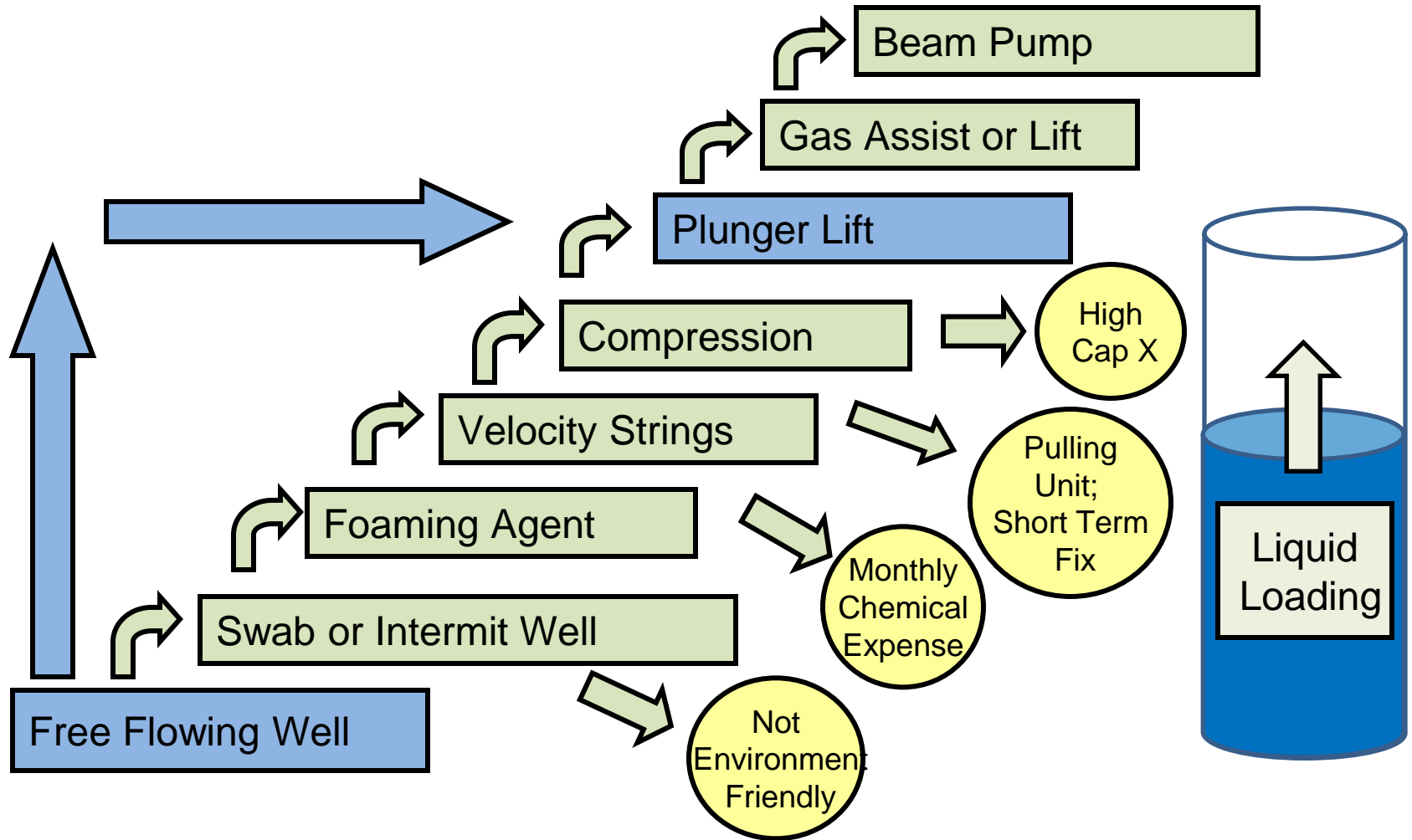


Why Is Artificial Lift Required

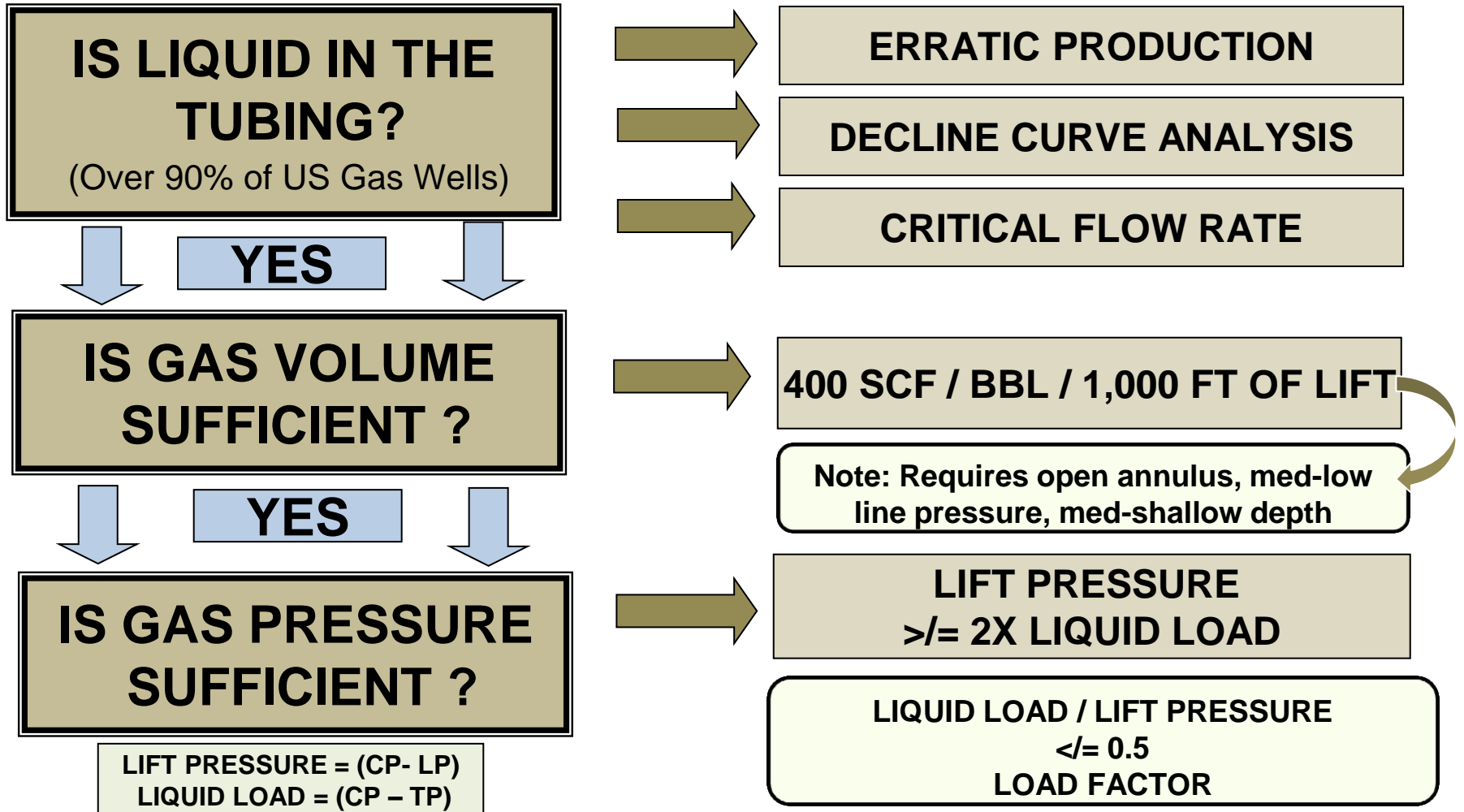


WHEN IS PLUNGER LIFT REQUIRED

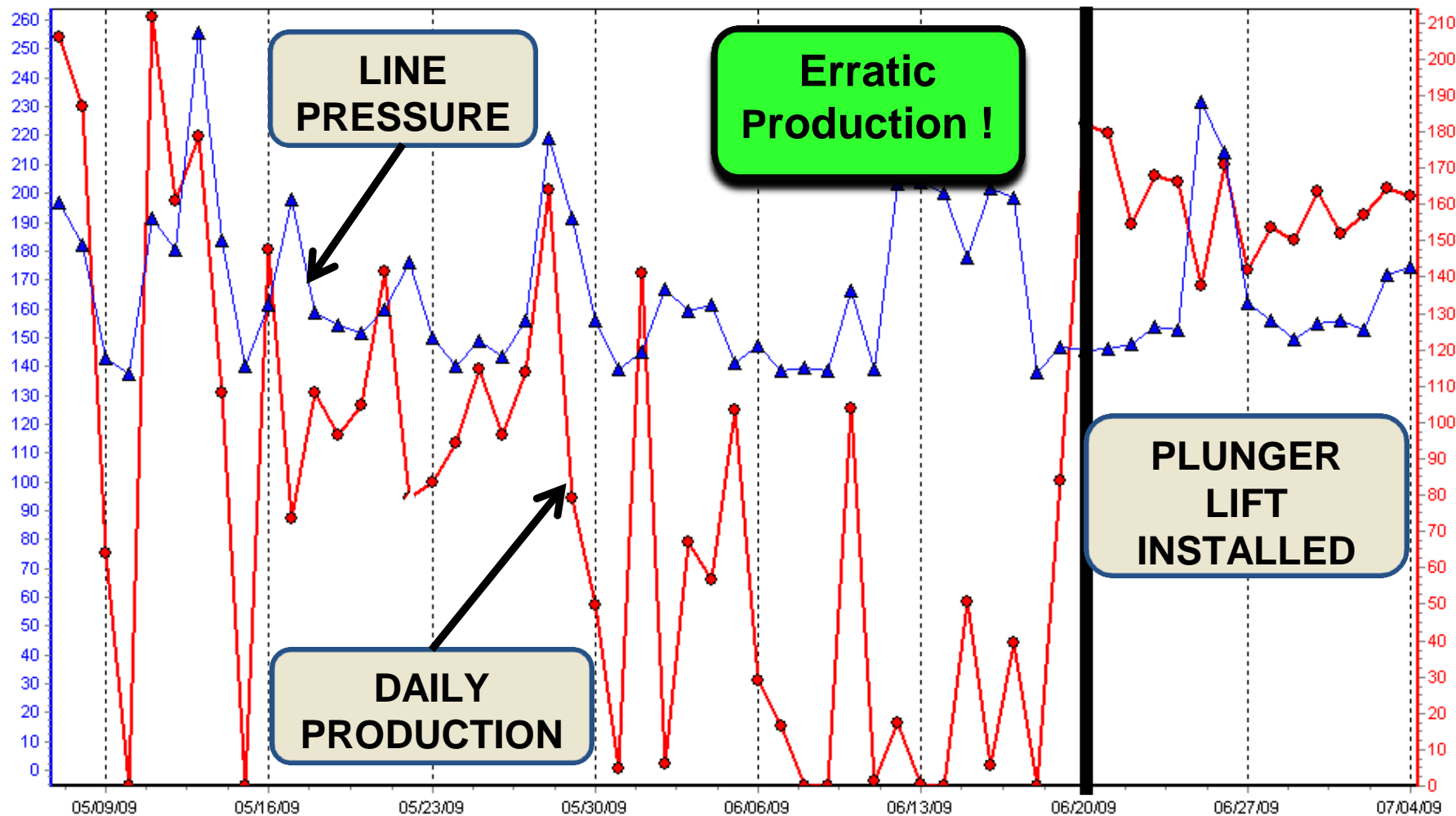
When Is Plunger Lift Required



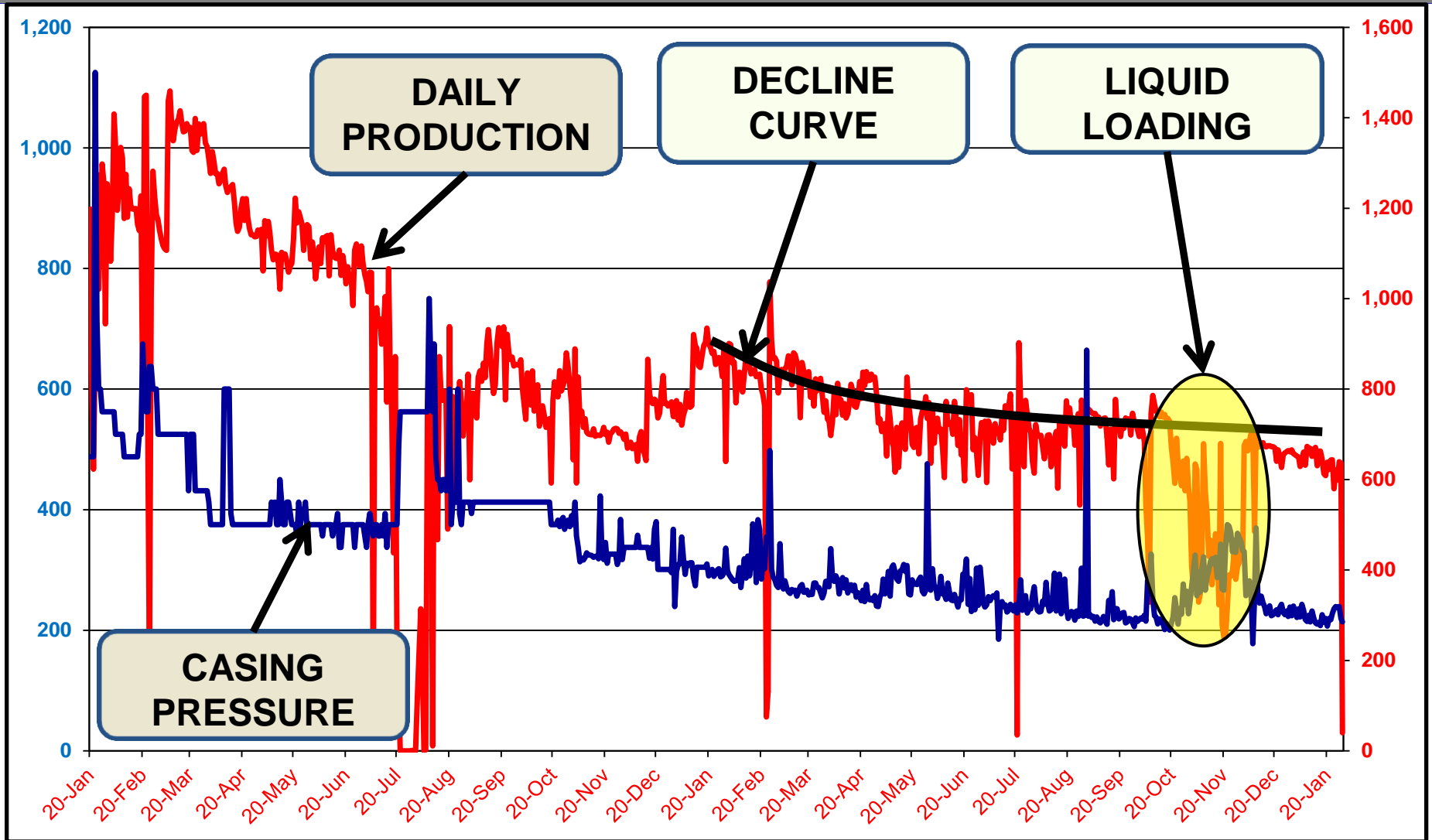
When Is Plunger Lift Required



When Is Plunger Lift Required



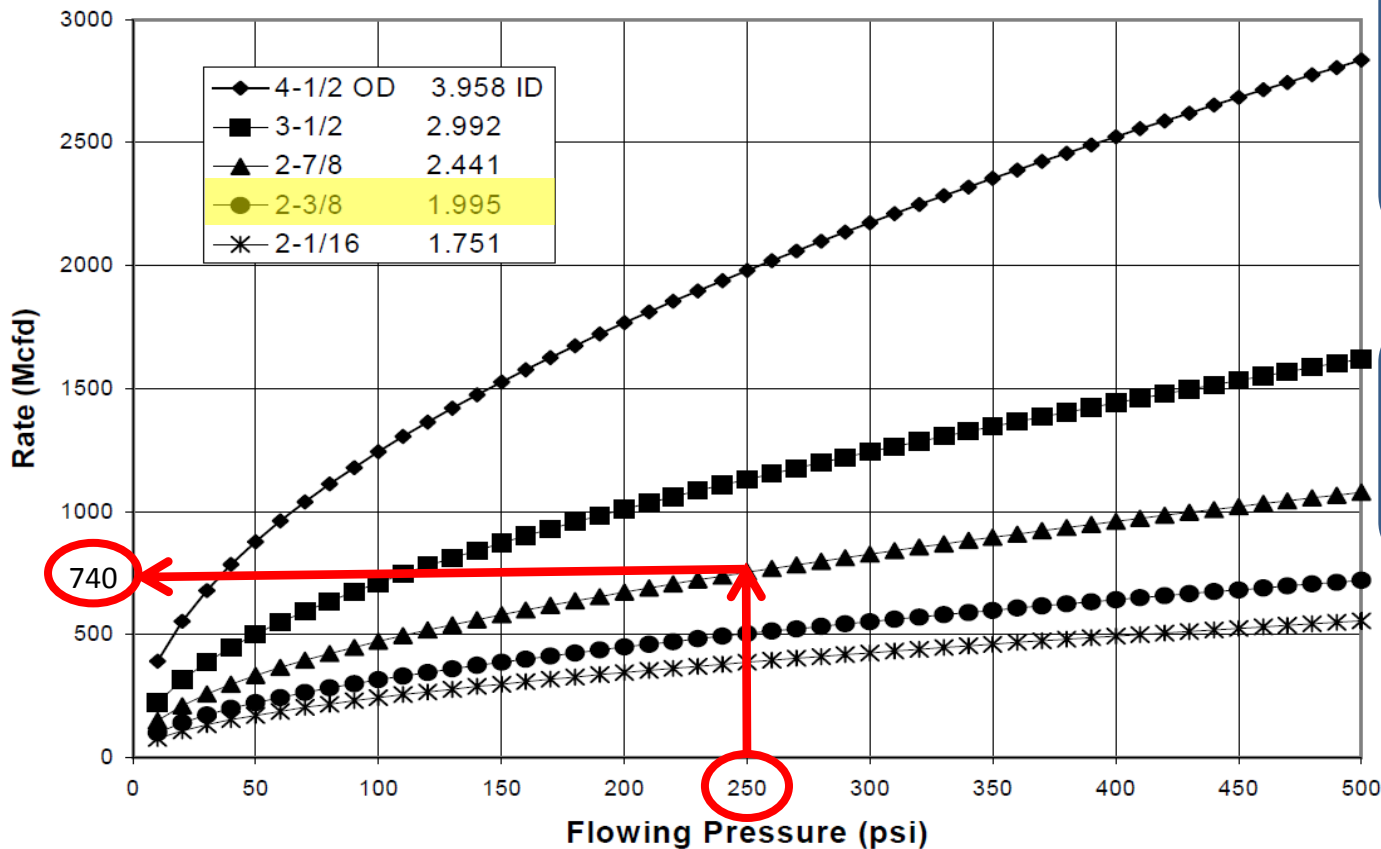
When Is Plunger Lift Required



When Is Plunger Lift Required

Provided By Echometer and PLTech LLC

Turner Unloading Rate for Well Producing Water



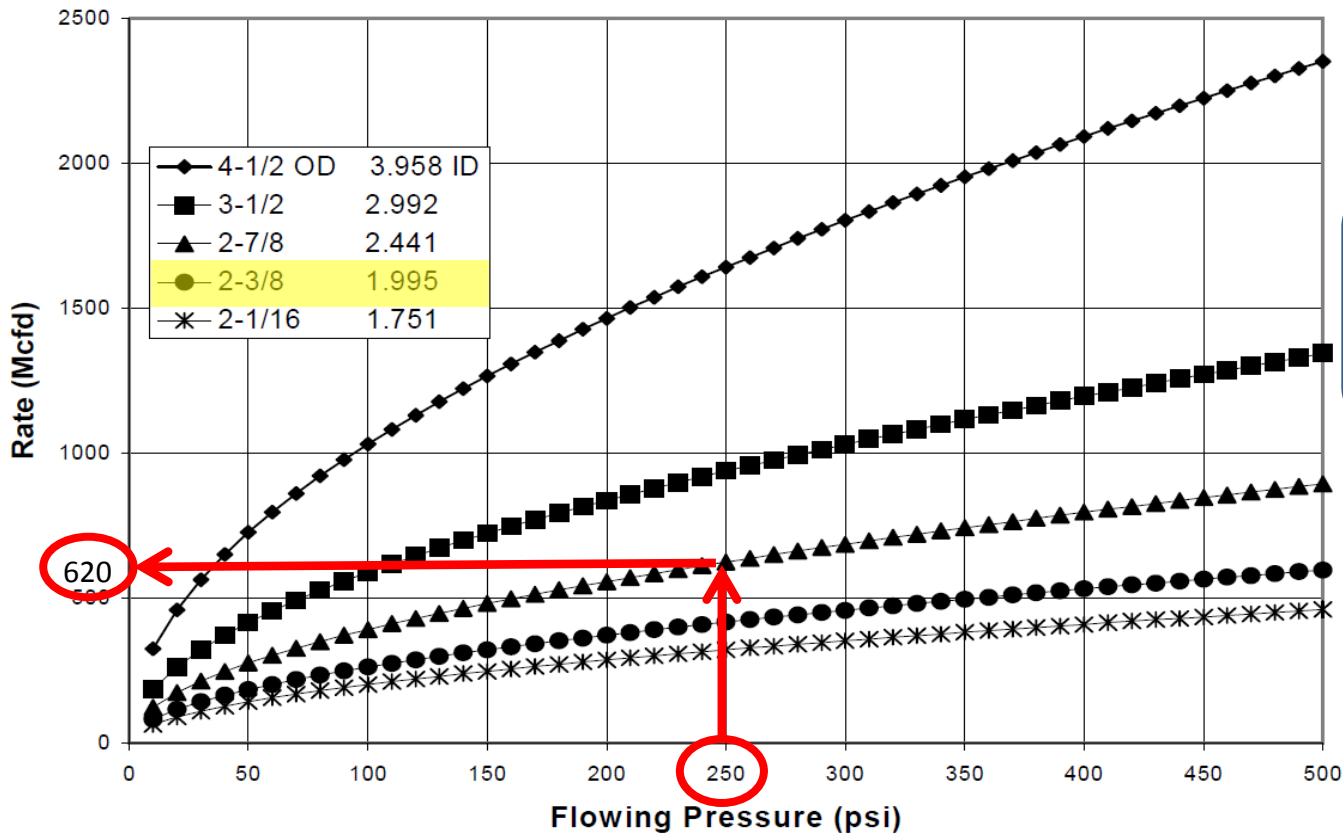
Empirical Study using wells with over 1,000 psi flowing tubing pressure

Predicted critical flow rate is 20% greater than Coleman

When Is Plunger Lift Required

Provided By Echometer and PLTech LLC

Coleman Unloading Rate for Well producing Water



Empirical Study using wells with flowing tubing pressure less than 1,000 psi

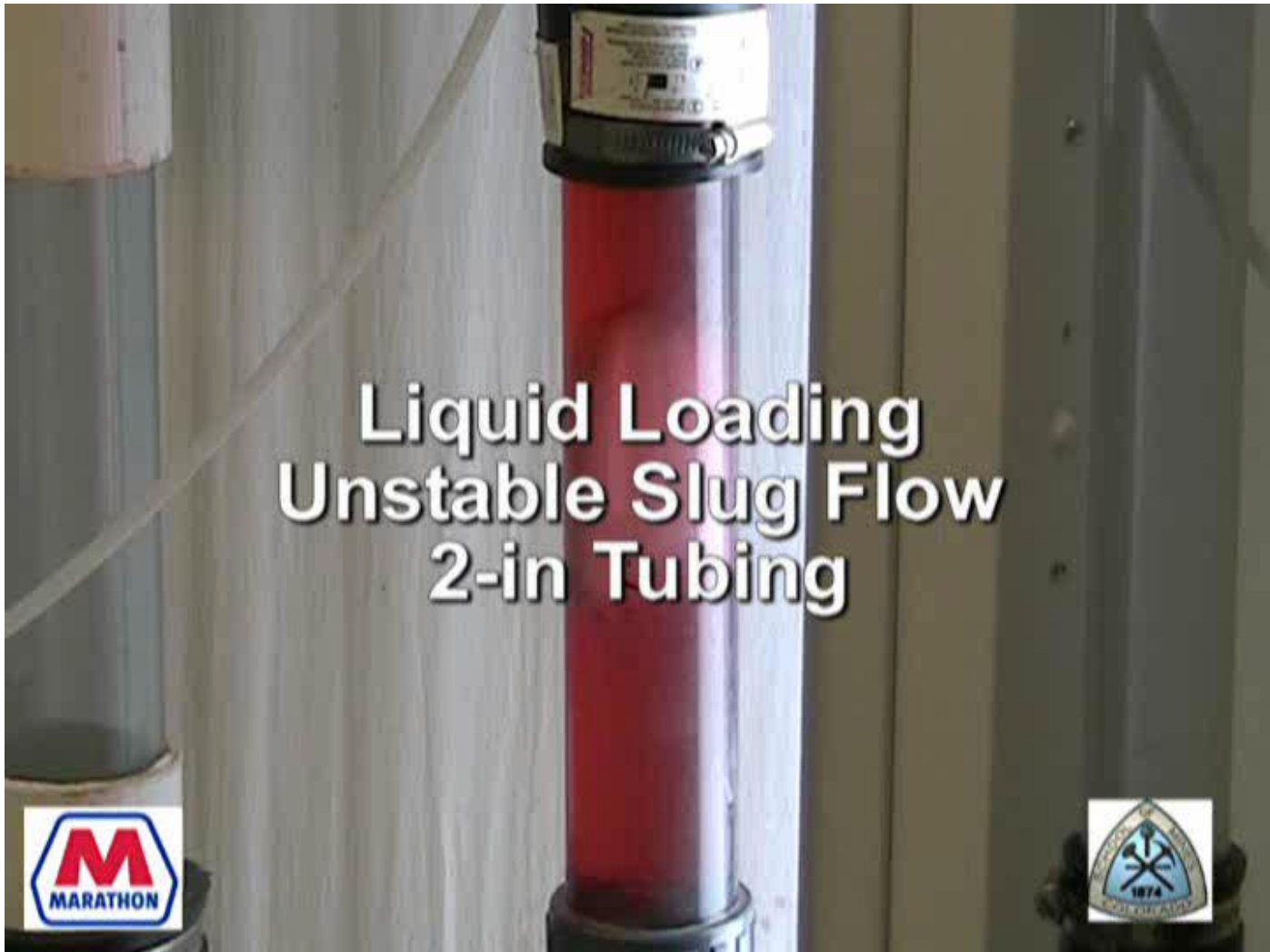
Predicted critical flow rate is 20% less than Turner

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

SPE Paper "A Systematic Approach to Predicting Liquid Loading in Gas Wells" by Gua, Ghalambor, Xu.

When Is Plunger Lift Required

VIDEO



When Is Plunger Lift Required

WELL DATA

Depth to BH Spring 7500 ft
Gas Production 200 Mcf/d
Liquid Production 10 Bbls/d
Pressures (Closed) TP 325 psi
CP 400 psi
LP 150 psi
Pressures (Open) TP = LP = 150 psi

IS GAS VOLUME SUFFICIENT?

(400 scf / bbl / 1,000 ft of lift)
Rule of Thumb

$400 \text{ scf} \times 10 \text{ bbls} \times 7500/1000$
 $= 30,000 \text{ scf or } 30 \text{ Mscf/d}$
Actual Volume is 200 Mcf/d

YES

IS FLUID IN THE TUBING?

Turner Critical Flow Rate = 400 Mcf/d
Coleman Critical Flow Rate = 320 Mcf/d
Actual Flow Rate is 200 Mcf/d

YES

IS GAS PRESSURE SUFFICIENT?

Liquid Load = CP – TP = 75 psi
Lift Pressure = CP – LP = 250 psi
Lift Pressure > 2 X Liquid Load
Load Factor = $75 / 250 = 0.3 (< 0.5)$

YES

BENEFITS

LIMITATIONS

ECONOMICS

Benefits (No Telemetry)

- **Stabilizes and improves production**
 - 10% to 20% production improvement is common
 - Keeps tubing clear of debris (Paraffin, scale, hydrates, etc)
 - Long term solution – produce well to depletion
 - Effective with vertical, directional, s-shaped and horizontal wells
 - Produces with a low casing pressure
- **Economical**
 - Low capital investment (Payback typically less than 60 days)
 - Low annual operating cost (Typically less than \$ 1,500 per year)
 - Reduces chemical cost
 - Reduces venting and swabbing
 - Reduces gas lift energy requirements by 30% to 70%
- **Good for the environment**
 - Reduces methane emissions and lost gas (less venting)
 - Operates on solar energy

Benefits (With Telemetry)

- **Stabilizes and improves production**
 - Allows skilled operator to control many wells
 - Optimize production using real time data and trends
 - Rapid and more accurate troubleshooting
- **Economical**
 - Allows identification and resolution of problems before profits are impacted
 - Enables reduction in windshield time (fuel, time, vehicle maintenance, safety, etc)
 - Enables reduction in equipment repair and maintenance
 - Enables reduction in unplanned well downtime
- **Safety**
 - Remote knowledge of key well site parameters
 - Remote shut-in of wells when necessary
 - Less drive time possible

Limitations

- **Liquid / Gas Content**
 - Up to 100 BBLs / D
 - 400 scf / BBL / 1000 Ft of Lift
 - Lift pressure at least 2X Liquid Load
 - Insufficient gas volume or pressure
- **Flow Stream Content**
 - High sand production, extreme paraffin content, excessive hydrates, low gravity crude oil
- **Mechanical Configuration**
 - End of tubing set too high or low
 - Flow line restrictions
 - Holes in tubing
 - Variations in tubing ID (Spring to Spring)
 - Difficult to operate with small tubing ID
 - Packer requires higher Gas to Liquid ratio
 - Bottom hole spring set at less than 50 degree deviation

Economics

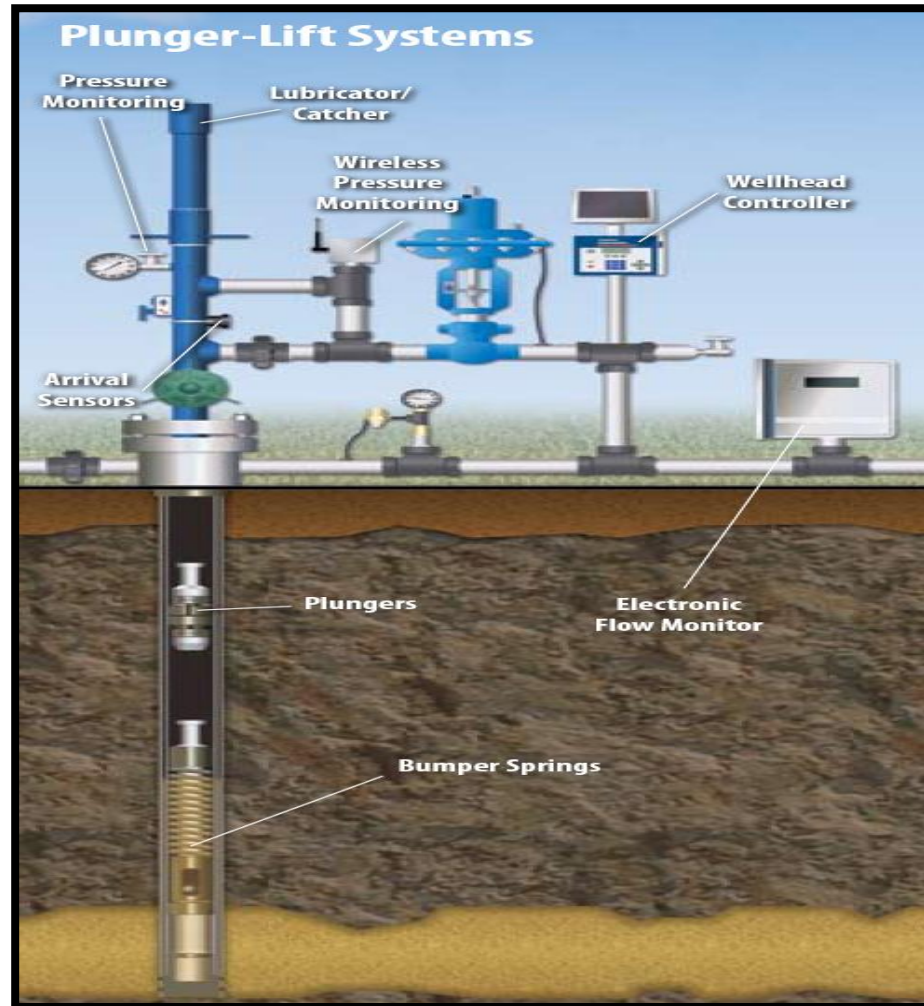
- Typical Costs
 - Capital and set-up (\$ 4,000 to \$ 15,000)
 - Annual maintenance (\$ 1,500)
- Revenue (\$ 4.00 / Mcf)

Flow Rate	10 % Increase	15 % Increase	20 % Increase	25 % Increase
100 Mcf/d	\$ 1,200 / mo	\$ 1,800 / mo	\$ 2,400 / mo	\$ 3,000 / mo
200 Mcf/d	\$ 2,400 / mo	\$ 3,600 / mo	\$ 4,800 / mo	\$ 6,000 / mo
300 Mcf/d	\$ 3,600 / mo	\$ 5,400 / mo	\$ 7,200 / mo	\$ 9,000 / mo
400 Mcf/d	\$ 4,800 / mo	\$ 7,200 / mo	\$ 9,600 / mo	\$ 12,000 / mo
500 Mcf/d	\$ 6,000 / mo	\$ 9,000 / mo	\$ 12,000 / mo	\$ 15,000 / mo

KEY COMPONENTS

Key Components

- ❑ Bottom Hole Spring
- ❑ Plunger
- ❑ Arrival Sensor
- ❑ Lubricator / Catcher
- ❑ Pressure Transducers
- ❑ Motor Valve(s)
- ❑ Gas Flow Meter
- ❑ Well Head Controller



Key Components

BOTTOM HOLE SPRINGS



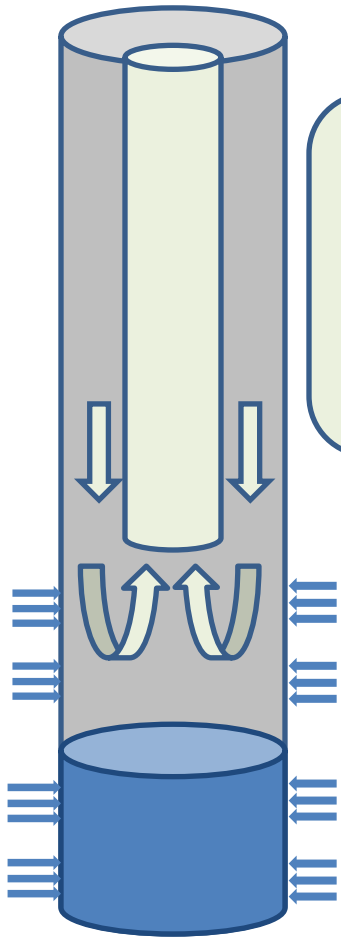
FUNCTION:

- Provides stop for the plunger
- Absorbs plunger impact
- Prevents damage to the plunger
- Protects the profile nipple
- Allows standing valve and pressure relief valve
- Holds liquid in the tubing

- 1) Standard bottom hole spring assembly with single cup hold down
- 2) Bottom hole spring assembly with single cup hold down and standing valve
- 3) Bottom hole spring assembly with tubing stop
- 4) Bottom hole spring assembly with collar stop
- 5) Bottom hole spring assembly with collet latch

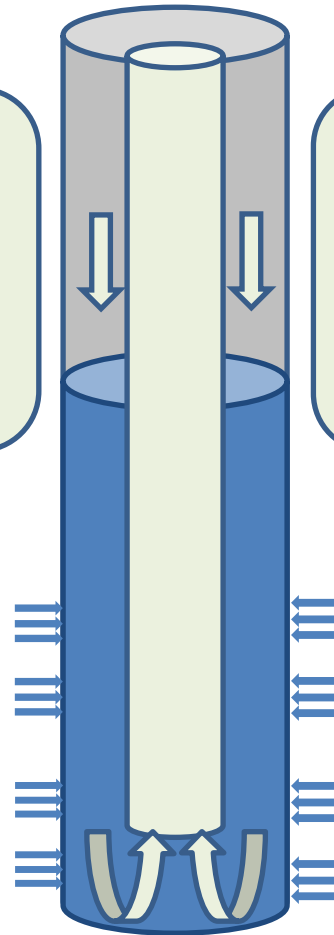
Key Components

END OF TUBING / SPRING LOCATION

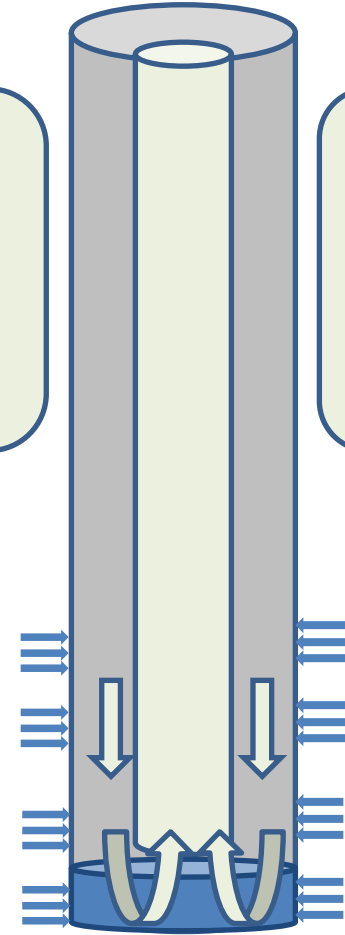


Tubing too high.
Liquid column
pressuring lower
zone, preventing
gas to flow freely.

Standing Valve!



Tubing too low,
or water column
too high. Clear
water column
and restart
plunger.



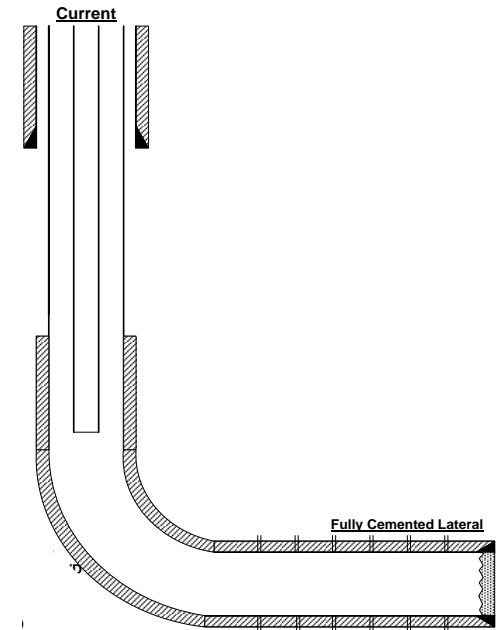
Tubing as low
as possible
and still
surface
plunger.
Prevent
backpressure
on entry zones

Key Components

SPRING LOCATION

MD	TVD	EW	NS	DIP	AZM
0	0	0	0	0	0
96	96	-0.33	-0.07	0.4	257.4
158	158	-0.88	-0.47	0.9	224.6
188	187.99	-1.1	-0.86	0.9	192.9
219	218.98	-1.08	-1.5	1.5	169.5
↓	↓	↓	↓	↓	↓
7382	7213.09	809.2	-451.33	43.6	13.8
7413	7235.11	814.22	-430.1	45.9	12.8
7445	7256.99	819.27	-407.3	47.8	12.2
7476	7277.16	824.2	-384.29	51	12
7508	7296.46	829.35	-359.3	54.8	11.3

No Packer



Key Considerations:

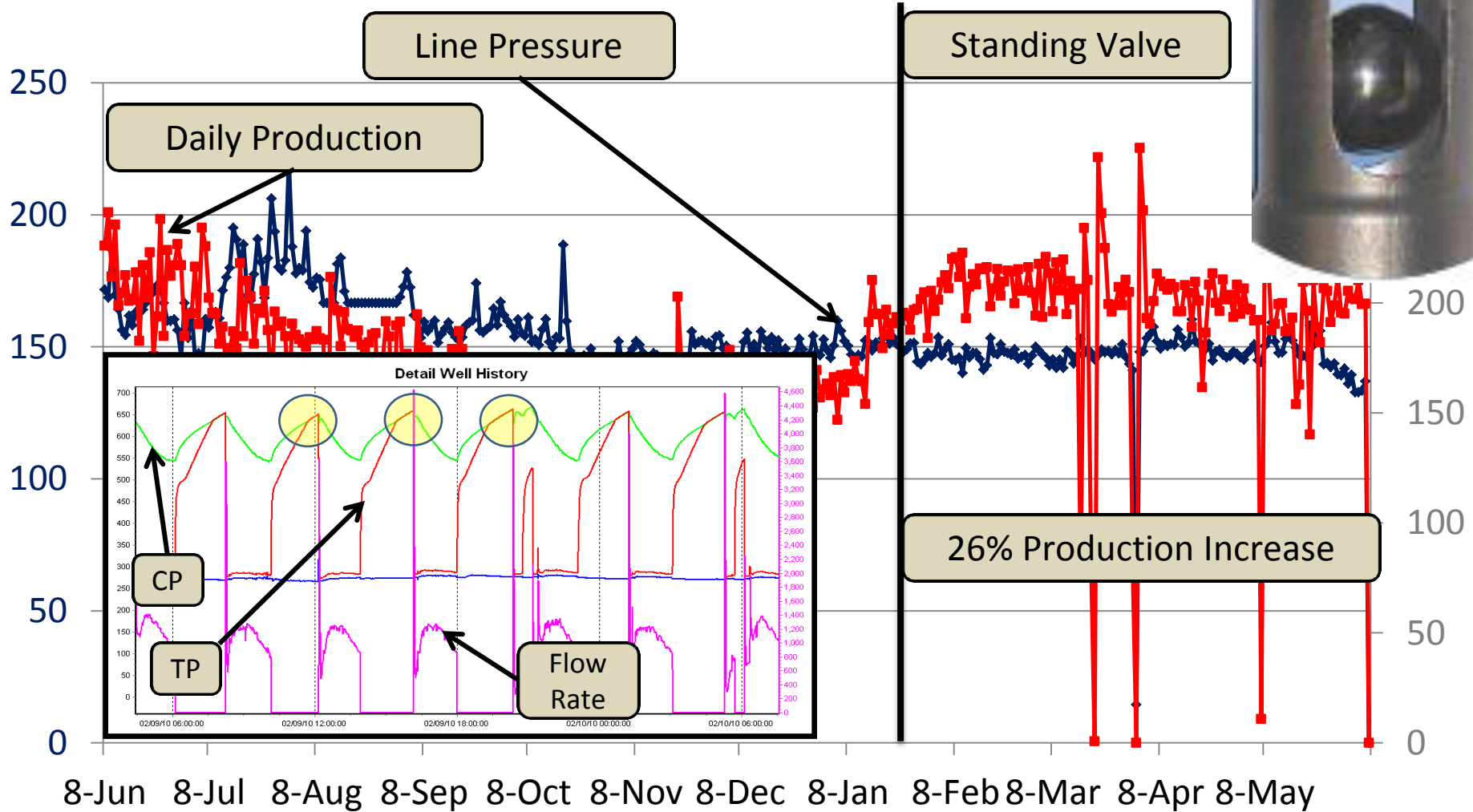
1. What is the tubing ID?
2. What are we anchoring to down hole?
3. If seating nipple, what is the ID (F, X, XN)?
4. What is the tubing deviation at the anchor point?
(Prefer less than 50 degree)
5. Is a standing valve and pressure relief spring required?
6. If vertical, where is the end of tubing relative to the perfs?

Tubing Details : (02/15/2008)

229 jts 2 3/8" 4.7 lb/ft, J-55, FBN tbg
 F Nipple @ 7432.9
 1 jt 2 3/8" 4.7 lb/ft, J-55, FBN tbg
 Notched Collar w/ ceramic disk
 EOT @ 7465 ft.

Key Components

STANDING VALVE



Key Components

PLUNGERS



1



2



3



4



5

FUNCTION:

- Interface between liquid and gas
- Push liquid to the surface
- Fall quickly to the bottom
- Clean debris from tubing ID
- Detectable by arrival sensor

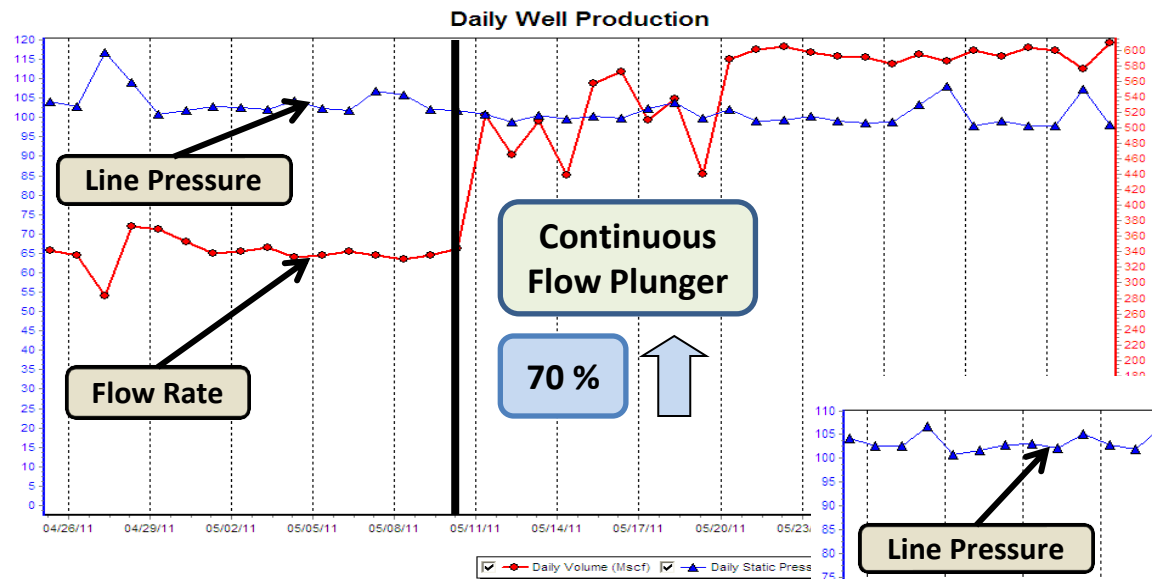
- 1) Cleanout plunger
- 2) Fiber seal (brush) plunger
- 3) Dual row pad plunger
- 4) Continuous flow plunger (Rod req'd)
- 5) Continuous flow plunger (No rod)

Key Considerations:

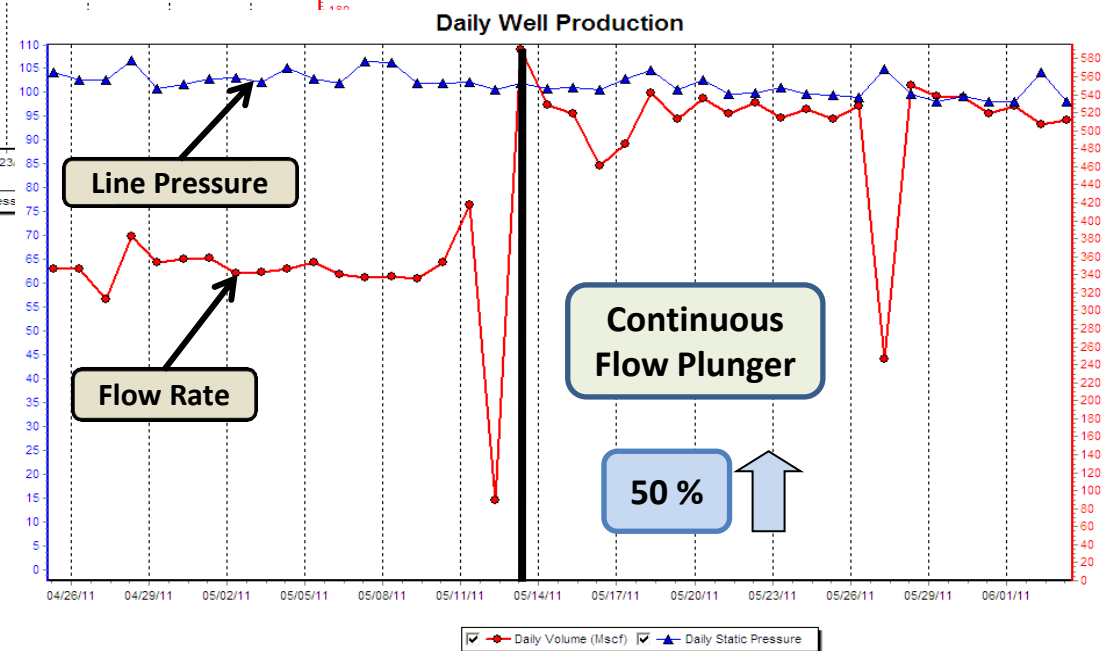
1. Use the correct plunger for the well!
 - Particulates?
 - Match fall speed to casing pressure build
 - Seal effectiveness?
2. When to replace the plunger?

Key Components

PLUNGERS



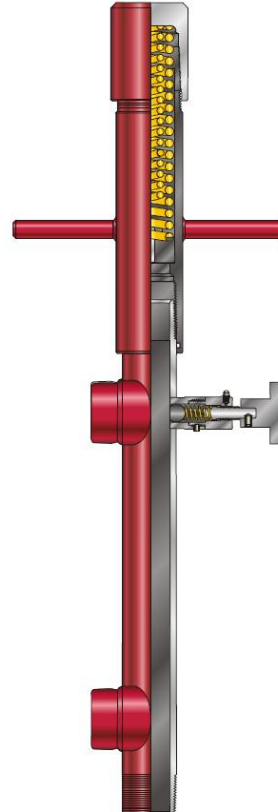
Use the right plunger for the well conditions



Replace worn plungers **BEFORE** production declines

Key Components

LUBRICATOR / CATCHER



FUNCTION:

- Absorb plunger impact
- Catch plunger at surface
- Ports for valves, transducers, arrival sensor

OPTIONS:

- Manual or auto catcher
- Single or dual outlet
- Threaded or flanged
- Cold weather certification

Key Components

ARRIVAL SENSOR

FUNCTION:

- Signal controller when plunger is at the surface



MOTOR VALVE

FUNCTION:

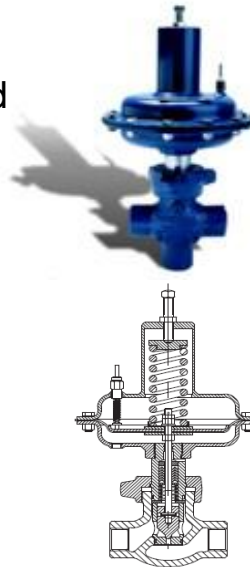
- Open and close the well as instructed by the controller

REQUIREMENTS:

- Adequate pressure rating
- Pressure opening
- Large trim size (Prefer same as pipe)

OPTIONS

- Trim kit material
- Threaded or flanged
- Straight or right angle



LATCH VALVE

(Solenoid Valve)

FUNCTION:

- Converts electrical signal to pneumatic signal to open or close the motor valve.

NOTE:

- Opening in solenoid valve is very small. Debris can easily clog, causing Motor Valve to remain open or closed.



Key Components

CONTROLLERS

FUNCTION:

- Signals well to open or close
- Collect, displays, transmits data
- Provide means to adjust plunger cycles
- May calculate gas flow rate
- May e-mail and text alarm conditions
- Simple to complex controls

Key Considerations:

1. Telemetry benefits desired?
2. Self adjusting benefits desired?
3. Algorithm selection considered?
4. Keypad at well site desired?
5. Well optimization support desired?
6. Standardize with EFM?



OPTIMIZE AND TROUBLESHOOT

Optimize And Troubleshoot

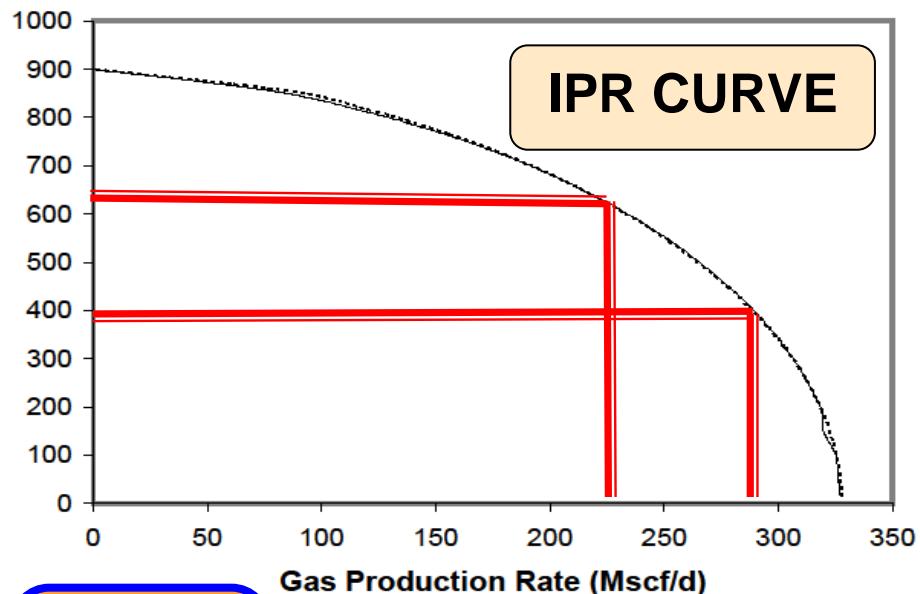
PRE-INSTALLATION

1. Well Data Sheet complete?
2. Is well a plunger lift candidate?
 - Liquid in the tubing?
 - Sufficient gas volume and pressure?
 - Check with clear tubing!
 - Minimal restrictions?
 - Packer, choke, trim size, orifice plate, line pressure, etc
 - Evidence of holes in tubing or blockage?
 - Sand? H₂S? CO₂?
 - Same ID spring to spring
 - Well head sleeve required?
3. Review prior 90 day production
4. Production target known?
5. Review well bore diagram.
 - Packer? Obstructions? Seating nipple locations? Type? ID?
6. Plumbing configuration known?
 - By-pass loop around motor valve
 - Dual Master Valves?
7. Bottom Hole Spring location
8. Preventative Maintenance Plan
9. Safety ! ! ! !
 - Trained Operators?

Optimize And Troubleshoot

- ***FOCUS ON PRODUCTION!***
- Use reliable hardware
- Minimize restrictions
- Use algorithms that address well variations
- On each cycle, review
 - Fluid in Tubing
 - Lift Pressure
 - Plunger Velocity
 - Gas Produced
- Troubleshoot – Use DATA !

Flowing Bottom Hole Pressure (psia)



Max
Cycles

Lowest
BHP

Smallest
Liquid
Loads

Most
Production

Optimize And Troubleshoot

PRODUCTION !

Plunger Lift Cycle Report

Station Name:
 Report Range: 02/01/11 08:00 To 02/13/11 20:49
 Site ID: 10099

Last Poll Time: 13-FEB-11 08:48PM
 Temperature: 58°F
 System Voltage: 13.2 V

Run #	AT CLOSE						AT OPEN					RUN DATA				PRODUCTION DATA				
	Time	Pressures (psi)				Fluid in Tbg	Time	Pressures (psi)			Act. Lift	Req'd Lift	Time (min)	Velocity (ft/min)	Arrivals		Open Duration	Close Duration	Gas (Mscf)	Liquid (Bbls)
CP	TP	SLP	CP-TP	CP	TP		SLP	Good	Miss											
3460	02/13/11 04:36AM	314	253	135	61	0.54	02/13/11 05:15AM	355	326	134	220	210	5.83	1339	1		00:06	00:38	6.0	0.0
3461	02/13/11 05:55AM	314	254	135	58	0.52	02/13/11 06:02AM	354	337	134	220	204	4.58	1704	1		00:05	00:40	5.5	0.0
3462	02/13/11 06:44AM	314	256	133	58	0.52	02/13/11 06:44AM	353	326	132	220	204	6.03	1294				00:36	5.8	0.0
3463	02/13/11 07:33AM	311	254	134	60	0.54	02/13/11 07:33AM	354	331	134	220	209	5.12	1526				00:41	5.3	0.0
3464	02/13/11 08:14AM	316	256	133	57	0.50	02/13/11 08:14AM	354	321	132	219	200	6.00	1302				00:35	6.4	0.0
3465	02/13/11 09:21AM	310	251	132	59	0.53	02/13/11 09:21AM	352	320	132	220	205	4.93	1583				00:39	5.3	0.0
3466	02/13/11 09:07AM	312	259	134	52	0.47	02/13/11 09:07AM	352	320	132	220	192	4.07	1920	1		00:05	00:43	5.9	0.0
3467	02/13/11 09:55AM	315	257	137	59	0.52	02/13/11 09:55AM	352	320	132	220	208	4.73	1650	1		00:05	00:44	5.4	0.0
3468	02/13/11 10:45AM	317	262	139	53	0.49	02/13/11 10:45AM	352	320	132	220	199	4.80	1627	1		00:05	00:39	5.4	0.0
3469	02/13/11 11:31AM	317	251	138	66	0.59	02/13/11 11:31AM	352	320	132	220	222	5.73	1362	1		00:06	00:35	5.9	0.0
3470	02/13/11 12:13PM	312	254	134	59	0.52	02/13/11 12:13PM	352	320	132	220	206	5.22	1497	1		00:06	00:40	5.5	0.0
3471	02/13/11 01:01PM	314	254	136	60	0.54	02/13/11 01:42PM	357	332	137	220	211	5.15	1517	1		00:06	00:41	5.0	0.0
3472	02/13/11 01:48PM	315	257	137	59	0.52	02/13/11 02:32PM	358	342	138	220	207	4.30	1816	1		00:05	00:43	5.8	0.0
3473	02/13/11 03:16PM	315	257	137	59	0.52	02/13/11 03:16PM	358	337	137	220	200	5.18	1507	1		00:06	00:39	5.8	0.0
3474	02/13/11 04:15PM	315	257	137	59	0.52	02/13/11 04:15PM	380	381	160	220	226	3.78	2064	1		00:04	01:22	6.1	0.0
3475	02/13/11 05:04PM	315	257	137	59	0.52	02/13/11 05:04PM	380	381	160	220	247	3.67	2130	1		00:04	01:10	7.2	0.0
3476	02/13/11 06:43PM	321	260	140	61	0.54	02/13/11 06:43PM	380	381	160	220	277	7.27	1075	1		00:04	00:29	5.2	0.0
3477	02/13/11 07:23PM	316	264	136	52	0.46	02/13/11 07:23PM	380	381	160	220	212	5.53	1411	1		00:04	00:33	5.6	0.0
3478	02/13/11 08:01PM	312	262	134	50	0.44	02/13/11 08:01PM	380	381	160	220	190	5.22	1497	1		00:04	00:32	6.4	0.0
3479	02/13/11 08:01PM	312	262	134	50	0.44	02/13/11 08:01PM	380	381	160	220	185	4.25	1838	1		00:04	00:37	4.9	0.0

Cycle #

Actual Lift Pressure (CP - LP)

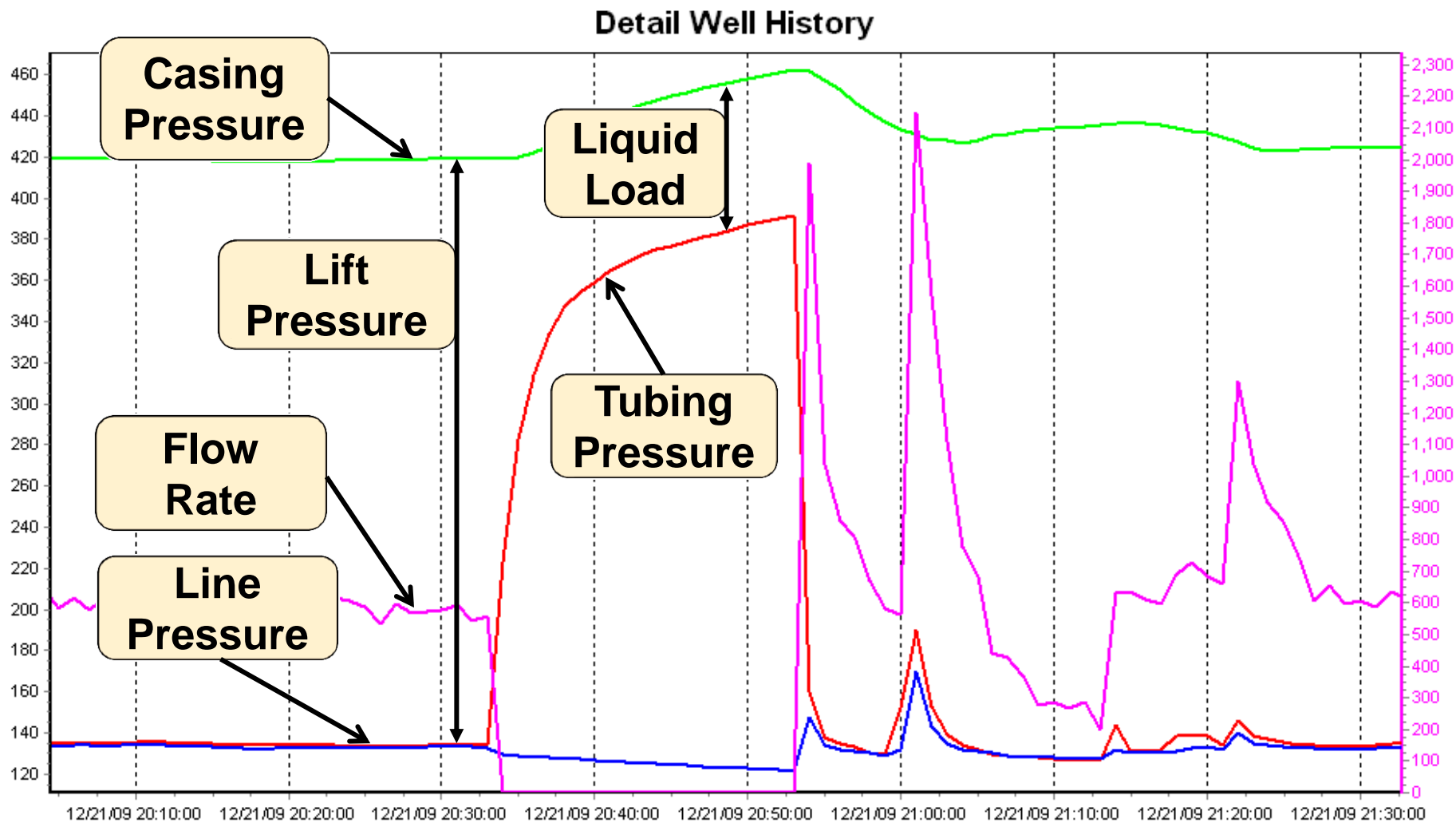
Liquid Load (CP - TP)

Calc Req'd Lift Pressure

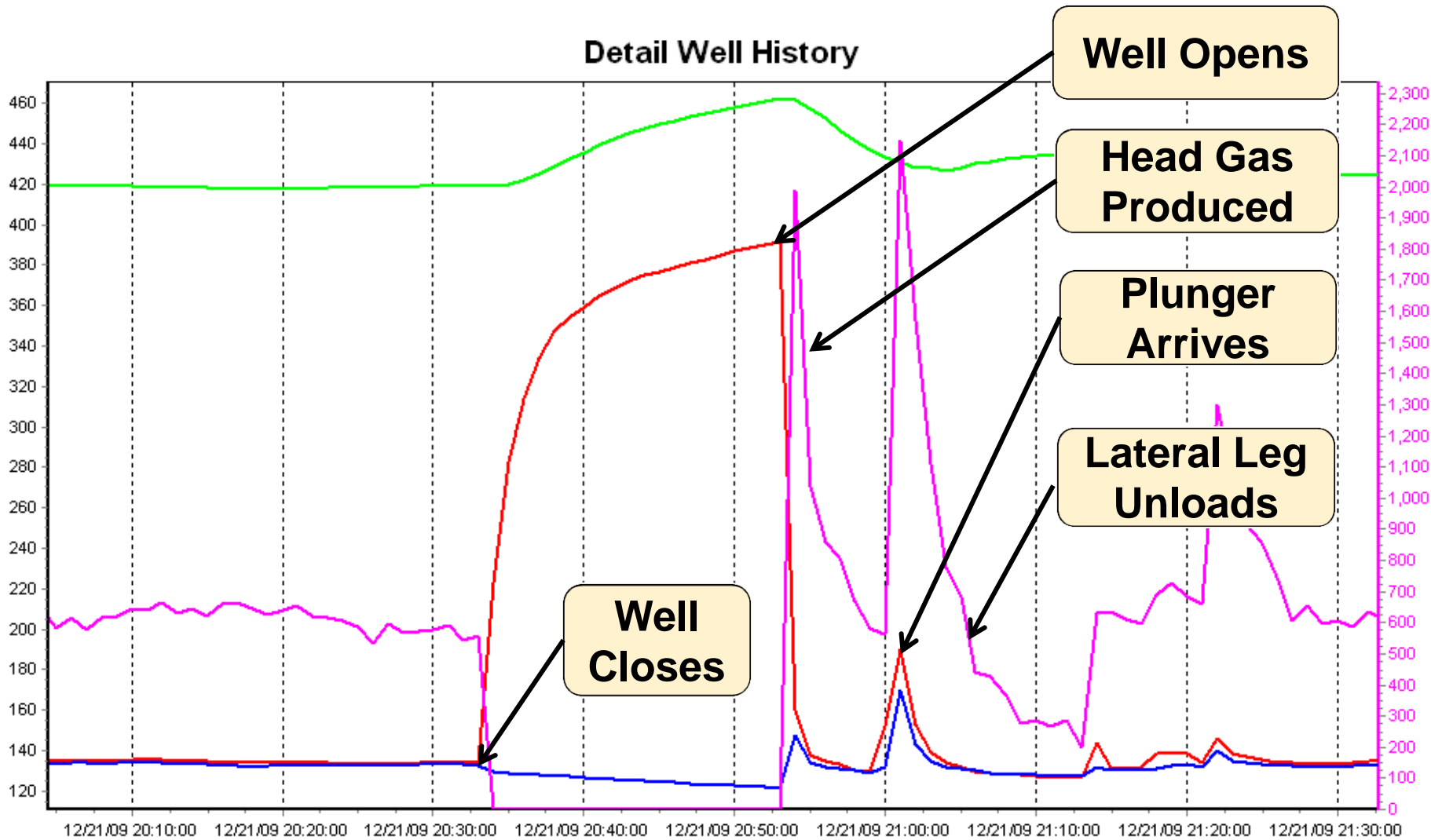
PLUNGER VELOCITY

CLOSE TIME

Optimize And Troubleshoot



Optimize And Troubleshoot



SAFETY

Safety

- **Arrive at site safely**
 - Avoid driving distractions. Drive courteously !
- **Job Safety Analysis (www.osha.gov)**
 - Identify the sequence of steps to complete the job
 - Identify hazards or potential hazards for each step
 - Identify every possible source of energy
 - Determine necessary actions to eliminate, control, or minimize hazards!
 - Each safe job procedure or action must correspond to the job steps and identified hazards
- **Wear appropriate Personal Protective Equipment !**

- **Injury**

- A technician was seriously injured when an unsuspected ice plug in the wellhead lubricator released and struck the worker in the head resulting in a fractured skull and permanent eye loss.

- **Contributing factors (partial list):**

- Ice build up in the lubricator assembly
- The ice build up in the lubricator was caused by produced water freezing in the assembly and no method of thawing the wellhead was available at this particular work site.
- Poor procedures in identifying potential hazards.
- Lack of operator training in safe work practices for the use of this equipment.

- **Noted sources of potential injury and equipment failure:**
 - Removing lubricator cap with contained pressure above or below ice plugs, sand bridges etc.
 - Ice build up in the spring housing
 - Paraffin, wax, sand and hydrates build up in the tubing string
 - Poorly designed springs or stops
 - Fast Plunger Arrivals
 - Plungers traveling “Dry” with little or no fluid
 - Changes in line pressure, causing fast arrivals
 - Change in plunger style used in well
 - No methanol injection or heat trace to keep ice and hydrates from forming

- **Noted sources of potential injury and equipment failure:**
 - Restricted flow path if the plunger is being held at surface causing a pressure drop and creating the environment for the formation of hydrates
 - Unexpected changes in flow regimes caused by cycling a plunger – sand production due to higher drawdown effect on the reservoir
 - High pressure and volumes of gas and fluid affecting surface equipment due to the cyclic nature of plunger operations impact of the plunger at surface

- **Be Safe by Design !**

What is your process ?

ADDENDUM

Well Data Sheet



Date:

WELL DATA SHEET

WELL LOCATION / OPERATOR DATA					
Well Name		State		Field	
County / Parish		API #		Formation	
Operator		Address			
Engineer Contact		E-mail		Mobile	
Field Contact		E-mail		Mobile	

WELL DATA												
WELL TYPE				WELLHEAD		WELL STATUS						
Gas	Oil	Sweet	Sour	Flanged	Threaded	Flow	Pump	Gas Lift	Intermit	Vent	Shut-in	T/A
WELL FORM				PACKER		SEATING NIPPLE						
Vertical	Horizontal	Directional	Other	Yes/No	Depth		F	X	XN	Other		
						ID						
						Depth						
WELL DEPTH					ATTACHMENTS							
TD (MD)	TVD	Kick-Off	GL	KB	Well Bore		Swab Report		BHP Test			
					Survey	Schematic						
TUBING / CASING / PERFORATIONS												
	Tubing	Casing	ZONE		Top Perf Depth		Bottom Perf Depth					
Size Wt / Grade Depth			1									
			2									
			3									
			4									
			5									
			6									

PRODUCTION DATA								
Production (24 hr flow)				Pressures				
Oil	Gas	Water	90 Day Production Chart Avail?	Tubing		Casing		Sales Line
				Flowing	Static	Flowing	Static	

RESERVOIR DATA							
API Gravity				Shut-in Pressures (24 Hour)			
Oil / Condensate				Tubing			
Gas Gravity				Casing			
Water Gravity				Bottom Hole			
	Sand	Paraffin	Salt	Scale	Iron Sulfide	Chlorides	% or PPM
Light							
Moderate						H ² S	
Heavy						CO ₂	

EQUIPMENT ON SITE			
Lubricator Type / Mfgr		SCADA Software	
Plunger Type / Mfgr		Tank Qty / Size	
Controller Model / Mfgr		Chem Pump Model	
Flow Meter Model / Mfgr		Standing Valve	

OPERATOR EXPECTATIONS

COMMENTS / PICTURES

Tubing Fluid Height and Volume

- **Fluid Volume in Tubing (Barrels)**
 - $FV = 0.002242 \times (CP-TP) \times (ID^2)/SG$
 - CP=Casing Pressure; TP=Tubing Pressure
 - ID=Tubing Inner Diameter (inches)
 - SG = Specific Gravity (1.0 for water)

- **Fluid Height in Tubing (Feet)**
 - $FH = (CP-TP) / (0.433 \text{ psi/ft} \times SG)$
 - 0.433 psi/ft = Pressure gradient of water
 - SG = Specific Gravity (1.0 for water)
 - Typically, fluid column is 20 % liquid, 80 % gaseous liquid (foam).
Divide results by 20% to obtain height of the gaseous liquid column

Tubing Fluid Height and Volume

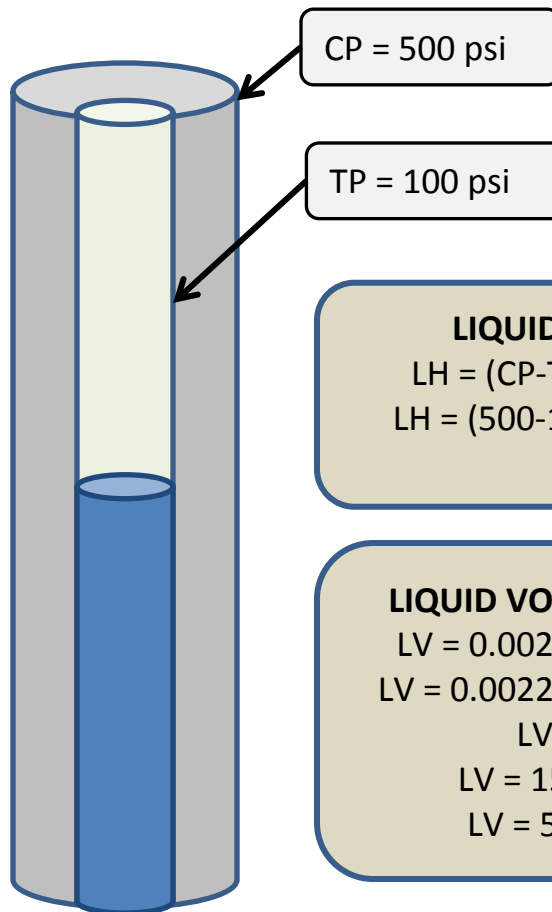
CP = Casing Pressure
TP = Tubing Pressure
ID = Tubing Inner Diameter (inches)
SG = Specific Gravity = 1.0 for Water
LH = Liquid Height in Tubing (Feet)
LV = Liquid Volume in Tubing (Bbls)
Water pressure gradient = 0.433 psi / ft

LIQUID HEIGHT IN TUBING

$$LH = (CP - TP) / (0.433 \text{ psi/ft} \times SG)$$

LIQUID VOLUME IN TUBING (BBLs)

$$LV = 0.002242 \times (CP - TP) \times (ID^2) / SG$$



LIQUID HEIGHT IN TUBING

$$LH = (CP - TP) / (0.433 \text{ psi/ft} \times SG)$$
$$LH = (500 - 100) / (0.433 \text{ psi/ft} \times SG)$$
$$LH = 923.78 \text{ ft}$$

LIQUID VOLUME IN TUBING (BBLs)

$$LV = 0.002242 \times (CP - TP) \times (ID^2) / SG$$
$$LV = 0.002242 \times (500 - 100) \times (ID^2) / SG$$
$$LV = 0.8968 \times (ID^2)$$
$$LV = 15.84 \text{ Bbls (2 3/8 tbg)}$$
$$LV = 5.34 \text{ Bbls (2 7/8 tbg)}$$

Casing Pressure Required

- **Foss and Gaul (CP Required to Lift Plunger)**
 - $CP_{req'd} = CP_{min} \times \{(A_{ann} + A_{tbg}) / A_{ann}\}$
 - $CP_{min} = \{SLP + P_p + P_c FV\} \times \{1 + D/K\}$
- **CP = Casing Pressure; SLP = Sales Line Pressure**
- **A_{ann} = Area Annulus; A_{tbg} = Area Tubing**
- **P_p = Pressure required to lift just the plunger**
- **P_c = Pressure Required to lift 1 bbl of fluid and overcome friction**
- **FV = Fluid Volume above the Plunger**
- **K = Constant accounting for gas friction below the plunger**
- **D = Depth of the Plunger**

Tubing	K	P _c
2 3/8	33,500	165
2 7/8	45,000	102
3	57,600	67

Standard Cubic Foot

- **SCF = ACF X P_f/P_s X T_s/T_f**
 - **SCF = Standard Cubic Foot of gas**
 - **Volume of gas contained in 1ft³ at 60°F and 14.7 psi**
 - **ACF = Actual or Measured Cubic Foot**
 - **P_f = Flowing pressure (psi); P_s = 14.7 psi**
 - **T_f = Flowing temperature (°R)**
 - **T_s = Standard temperature (516.67°R)**
 - **°R = °F + 459.67**

Critical Flow Rate

- **Critical Flow Rate (Coleman, P_f Less Than 1,000 psi)**
 - $CV_{\text{water}} = 4.434 \times \left[\frac{(67 - 0.0031P_f)^{1/4}}{(0.0031P_f)^{1/2}} \right]$
 - $CV_{\text{condensate}} = 3.369 \times \left[\frac{(45 - 0.0031P_f)^{1/4}}{(0.0031P_f)^{1/2}} \right]$
 - $FR = CV \times [\pi \times (ID/2)^2] \times (1 \text{ ft}/144 \text{ in}^2) \times 86,400 \text{ sec/day}$
 - CV = Critical Velocity (ft/sec)
 - FR = Flow Rate (scf/d)
 - P_f = Flowing Pressure
 - ID = Tubing Inner Diameter
- **Turner (P_f Greater Than 1,000 psi)**
 - Turner = Coleman + 20%

Rules of Thumb

- **Gas Volume Required**
 - **No Packer**
 - **400 scf per bbl per 1000 ft of lift**
 - **Packer**
 - **2,000 scf per bbl per 1000 ft of lift**
- **Casing Pressure at least 1.5 X line pressure**
 - **$CP \geq 1.5 \times SLP$**
- **Lift Pressure at least 2 X greater than fluid load**
 - **$(CP - SLP) \geq 2 \times (CP - TP)$**

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