Gas Well Deliquification Workshop

Sheraton Downtown Denver Hotel

Denver, Colorado

February 18 - 20, 2013

Introduction to Plunger Lift

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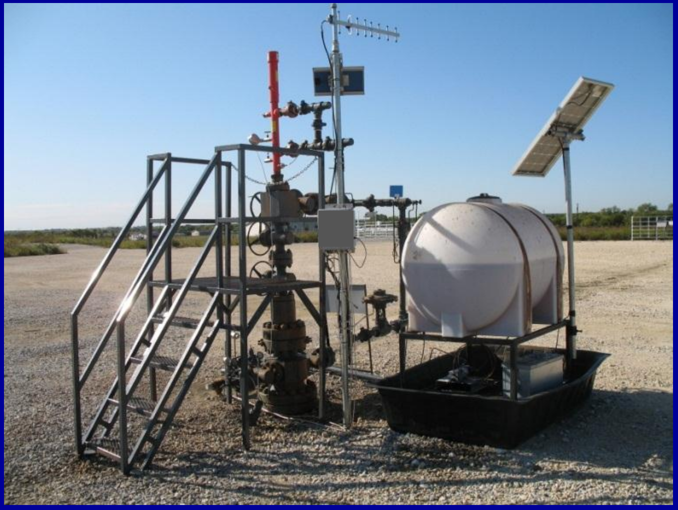
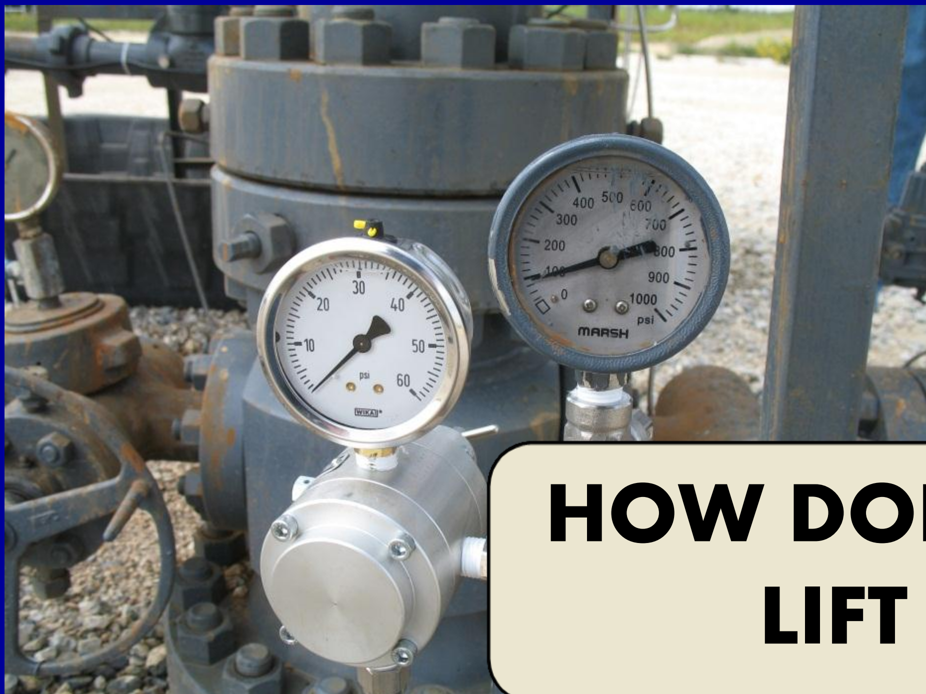
Shale Tec LLC



Introduction to Plunger Lift

- How does plunger lift work
- Why is artificial lift required
- When is plunger lift required
- Applications and benefits
- Installation and operation
- Safety

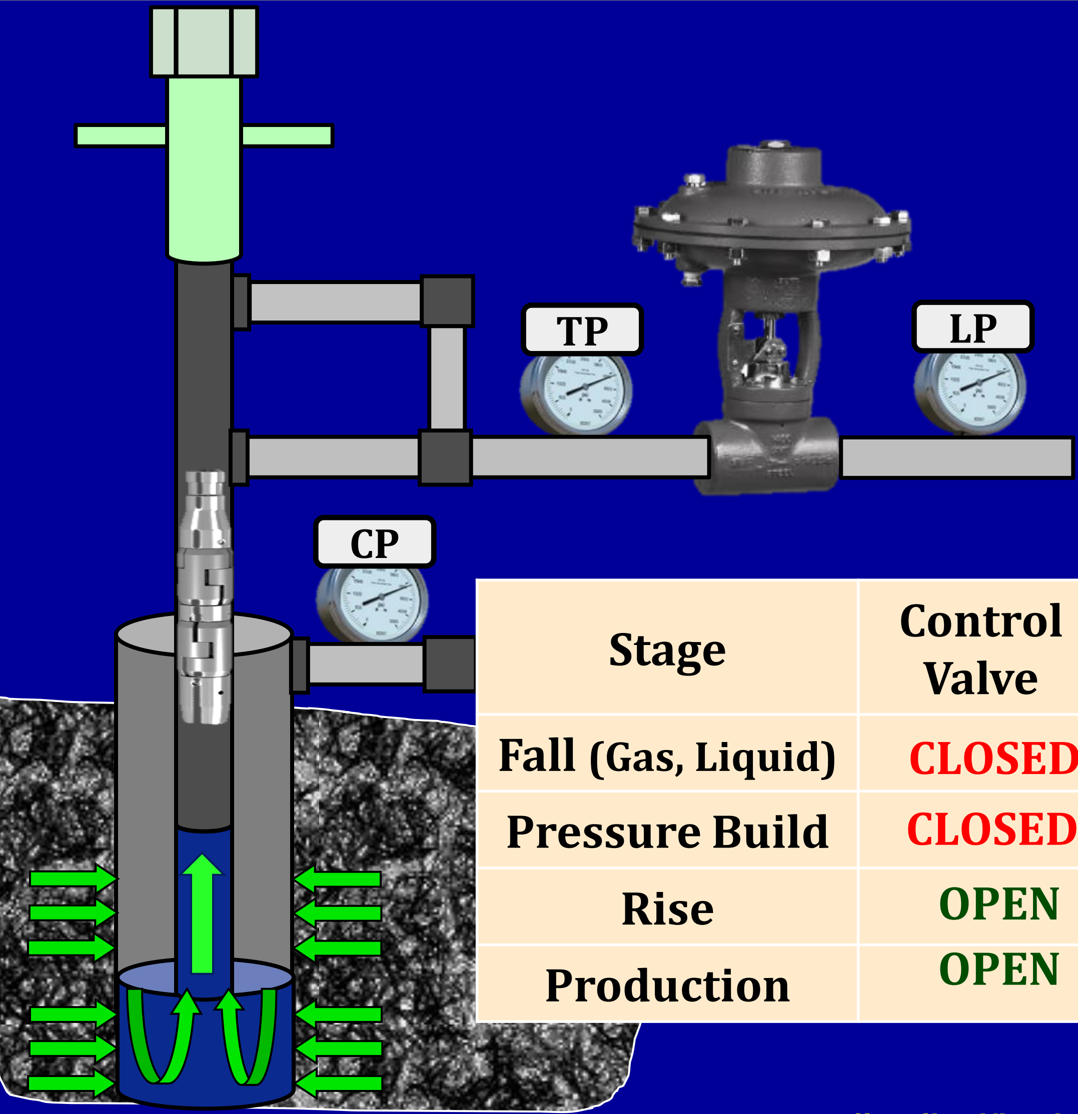


HOW DOES PLUNGER LIFT WORK

How Does Plunger Lift Work

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

How Does Plunger Lift Work



PLUNGER FALL VELOCITY
SPE 80891 – Determining how different plunger manufacturer features affect plunger fall velocity

LIQUID LOAD = (CP – TP)

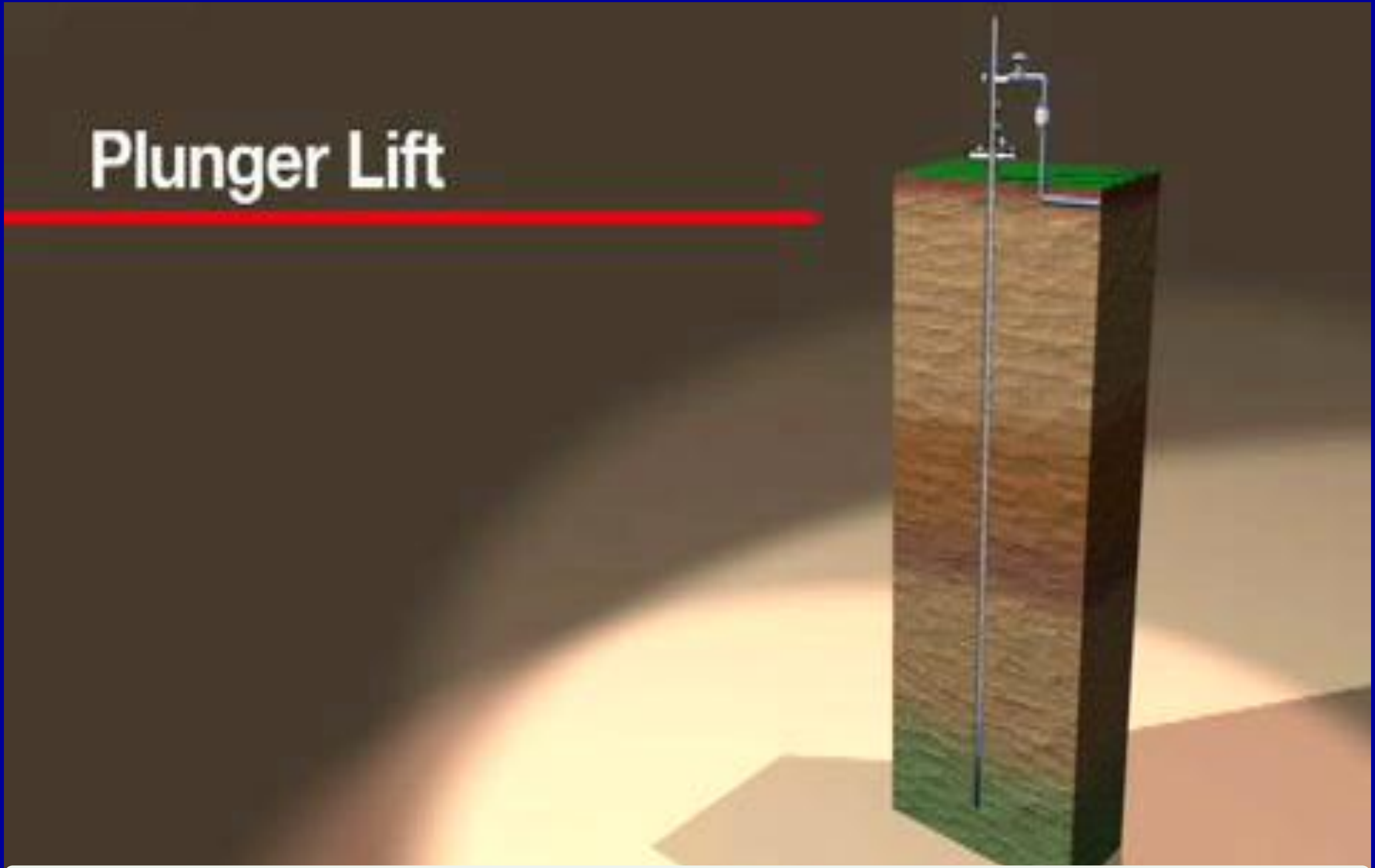
LIFT PRESSURE = (CP- LP)

FOSS and GAUL
SPE 120636 – Modified Foss and Gaul model accurately predicts plunger rise velocity

Stage	Control Valve	Gas Flow	Plunger	Casing Pressure
Fall (Gas, Liquid)	CLOSED	NONE	FALLING	INCREASE
Pressure Build	CLOSED	NONE	BOTTOM	INCREASE
Rise	OPEN	FLOW	RISING	DECREASE
Production	OPEN	FLOW	SURFACE	DECREASE

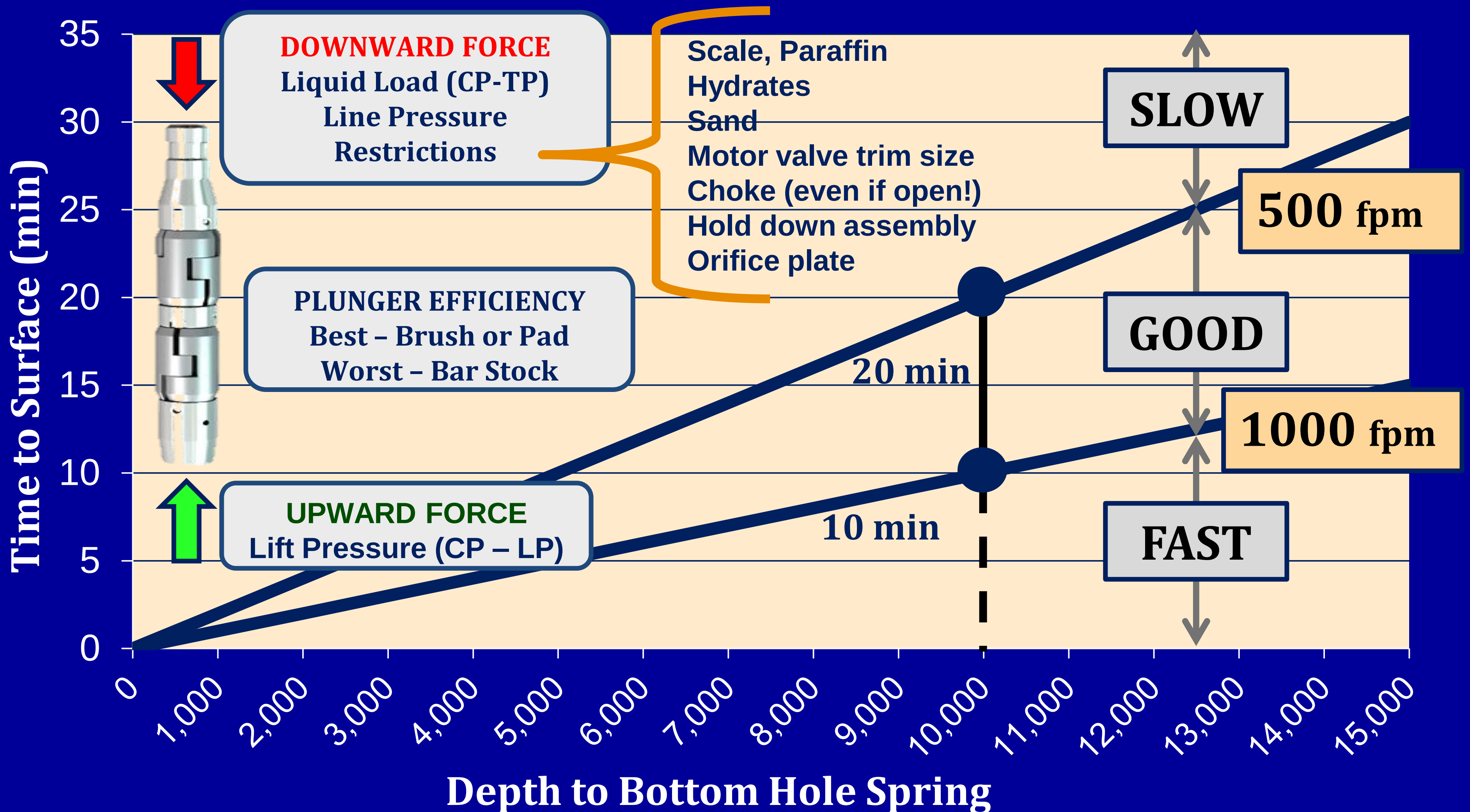
How Does Plunger Lift Work

Video courtesy of PCS Ferguson



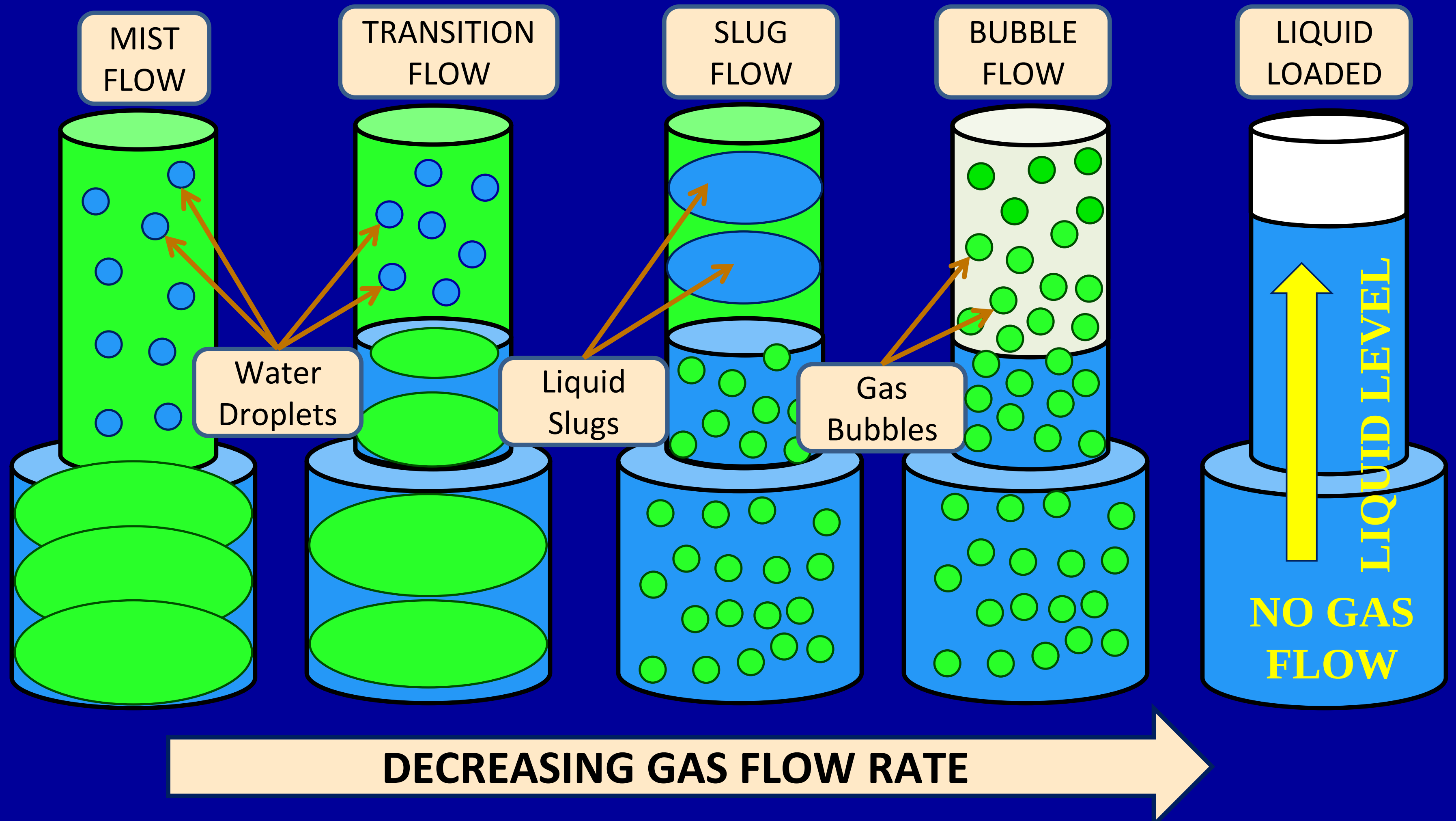
Production Control Services (PCS) and Ferguson Beauregard are now PCS Ferguson

How Does Plunger Lift Work



WHY IS ARTIFICIAL LIFT REQUIRED

Why Is Artificial Lift Required

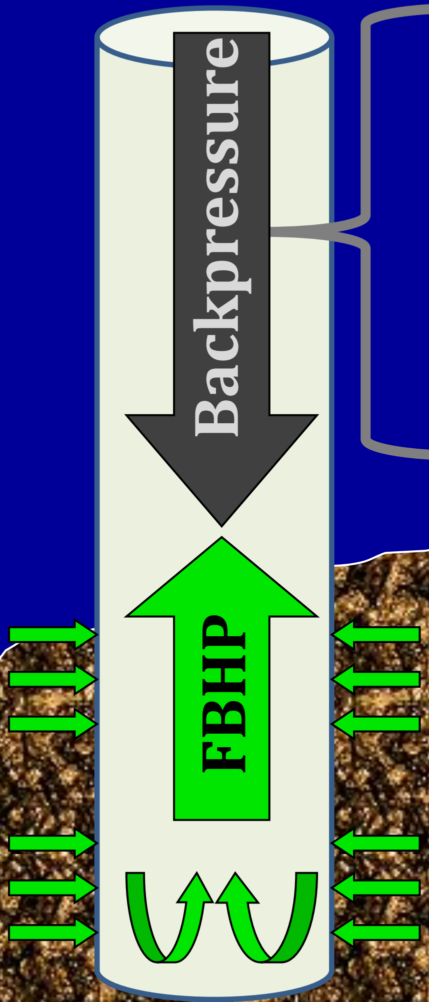


Why Is Artificial Lift Required

Video courtesy of PCSFerguson

Production Control Services (PCS) and Ferguson Beauregard are now PCS Ferguson

Why Is Artificial Lift Required



- Line Pressure
- Liquid
- Scale / Paraffin
- Chokes
- Control Valve Trim
- Orifice Plate
- Multiple 90 degree elbows

LOW Backpressure

Produces

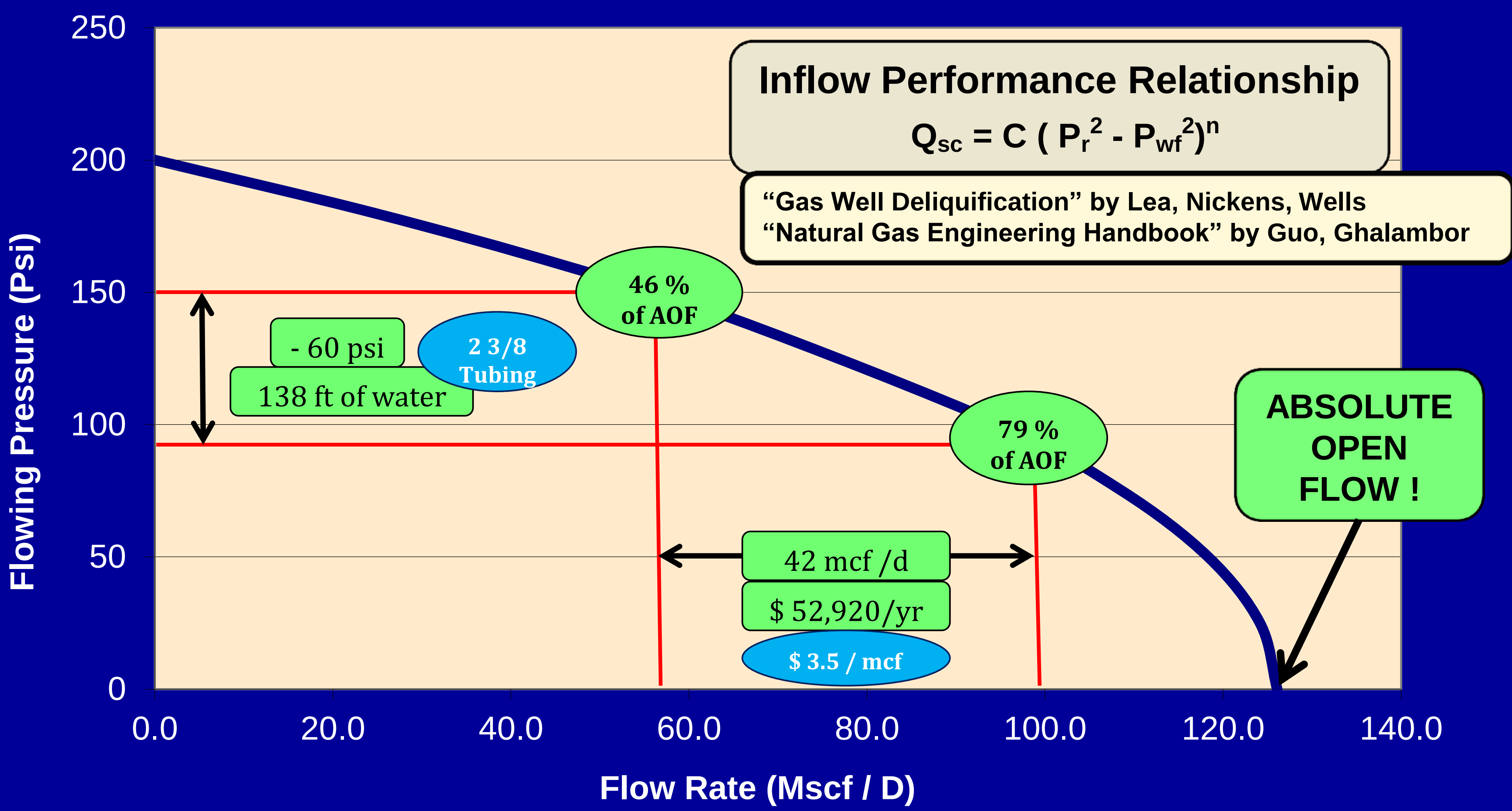
LOW FBHP

Ensures

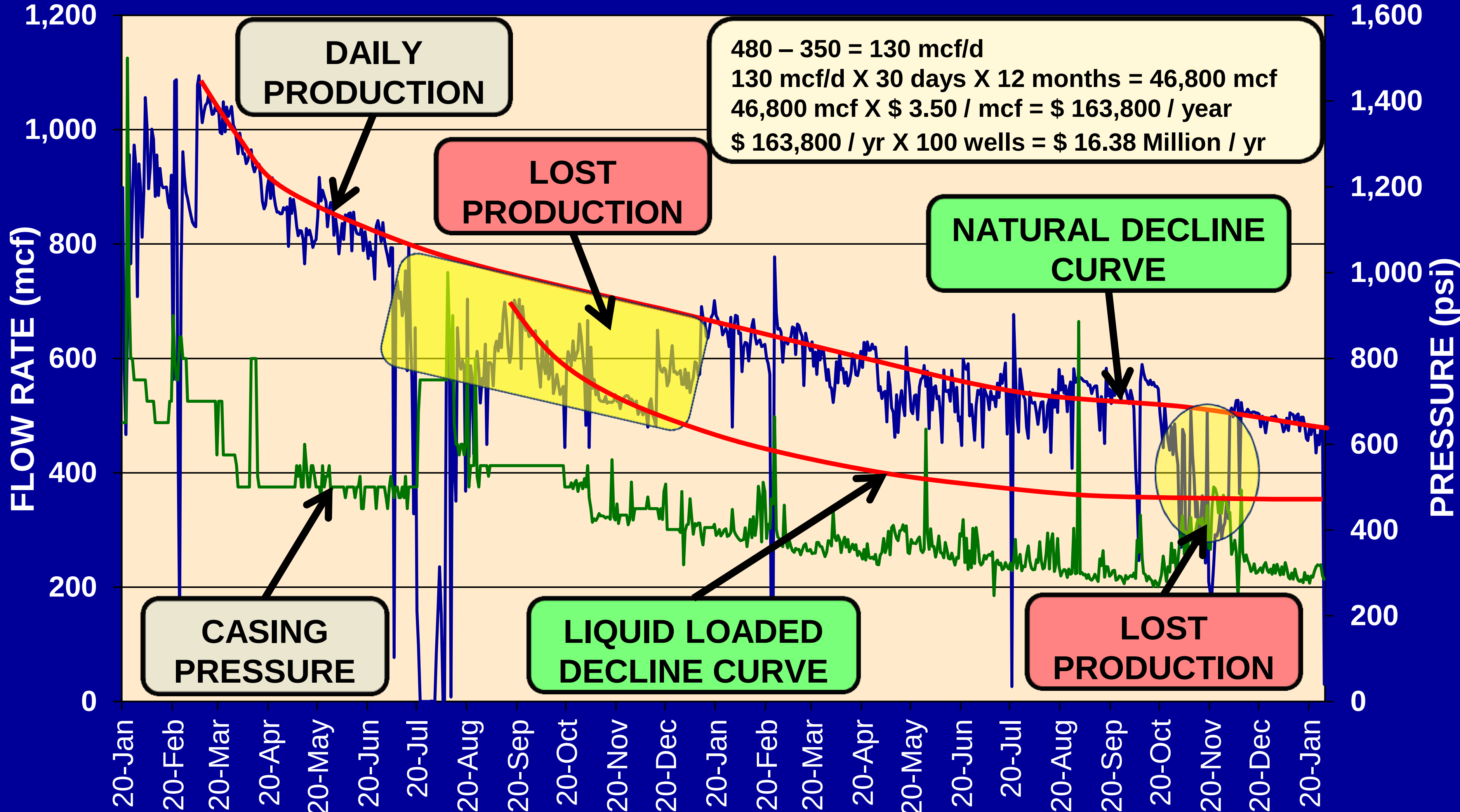
MOST Production

FLOWING BOTTOM HOLE PRESSURE

Why Is Artificial Lift Required



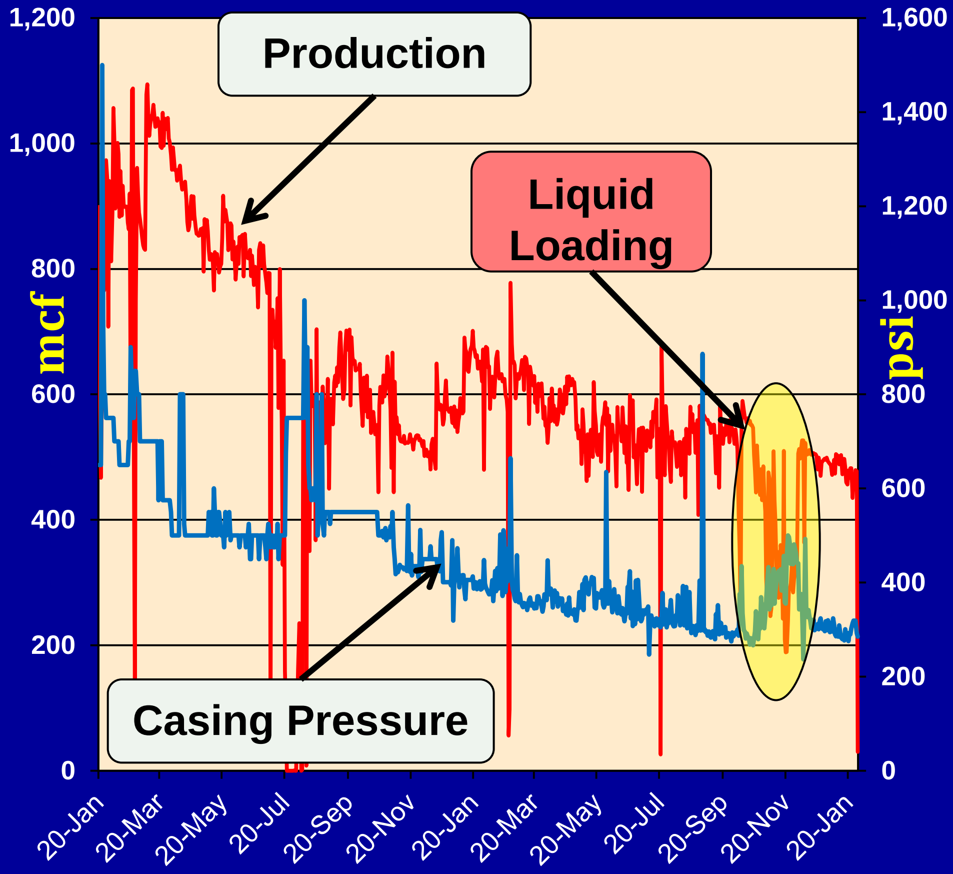
Why Is Artificial Lift Required

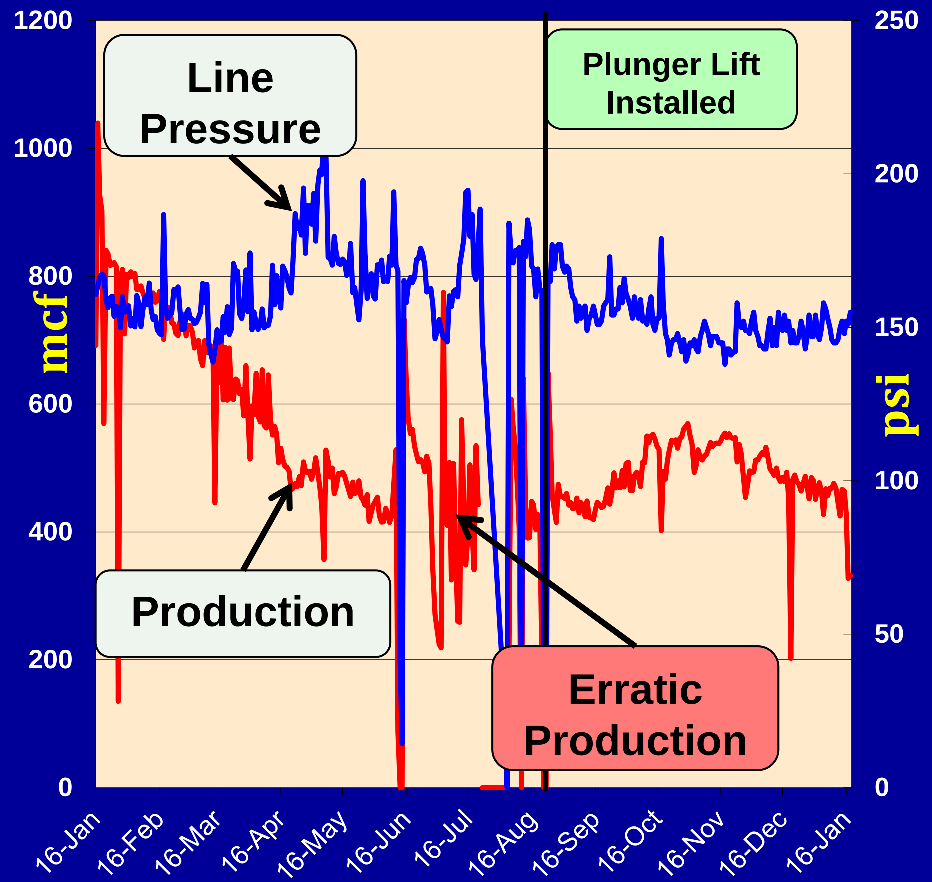


PLUNGER LIFT WELL REQUIREMENTS

Plunger Lift Well Requirements

IS LIQUID IN THE TUBING ?





Plunger Lift Well Requirements

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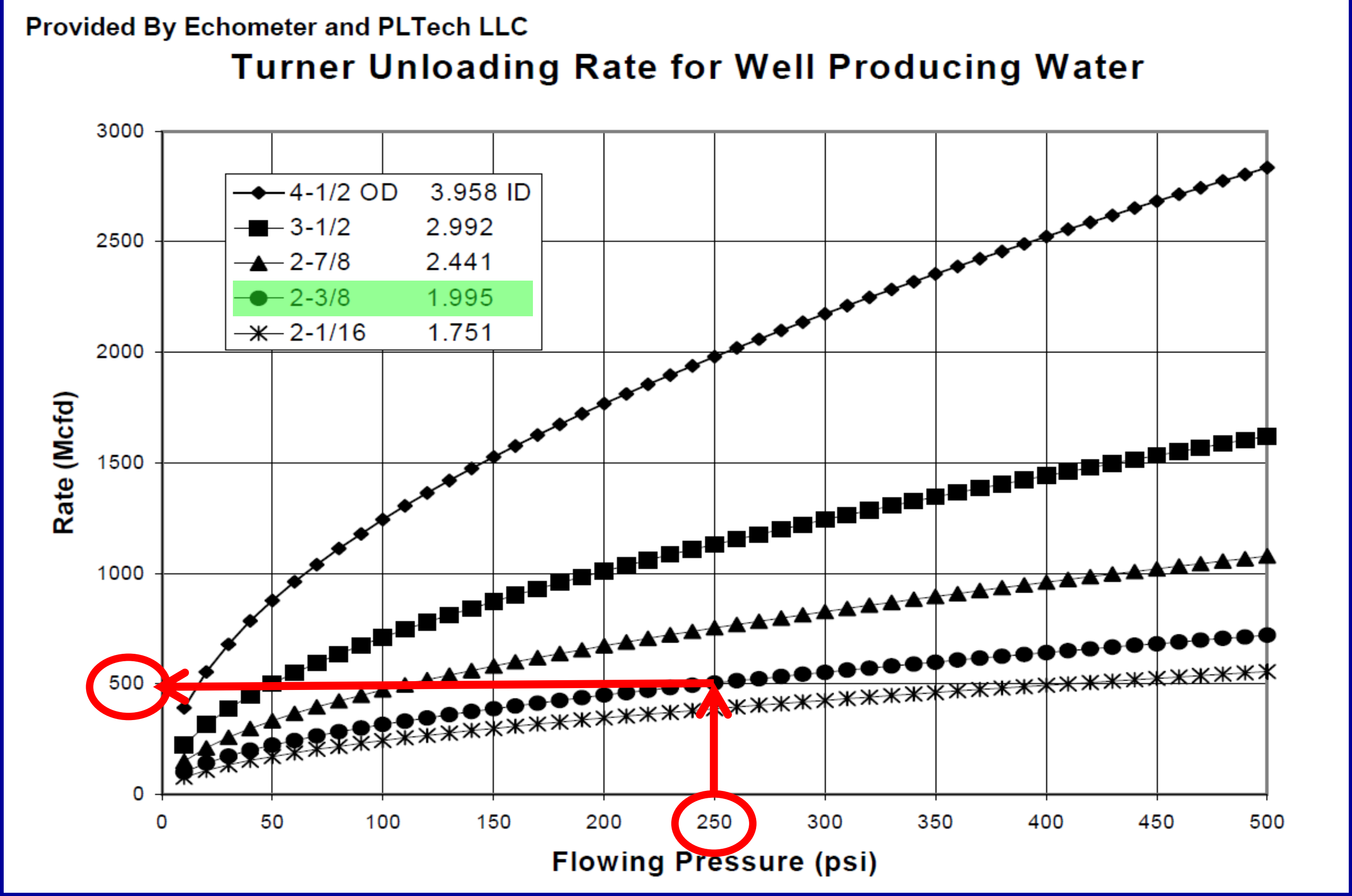


What's happening at bottom of well?

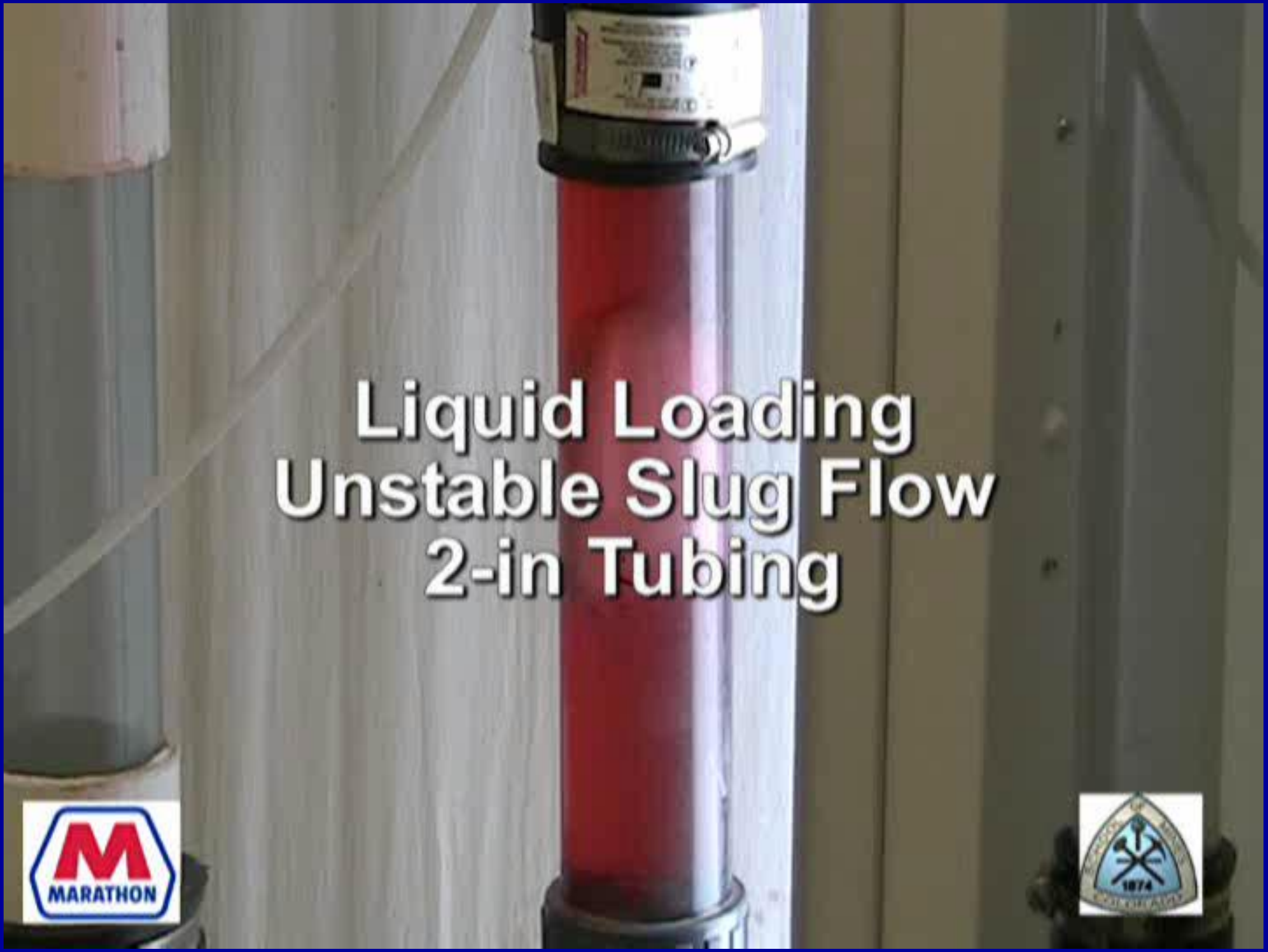
Coleman Critical Flow Rate is 20% lower than Turner

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

SPE 94081 "A Systematic Approach to Predicting Liquid Loading in Gas Wells" by Gua, Ghalambor, Xu.

Plunger Lift Well Requirements

Video courtesy of Marathon



Plunger Lift Well Requirements

IS GAS VOLUME SUFFICIENT ?

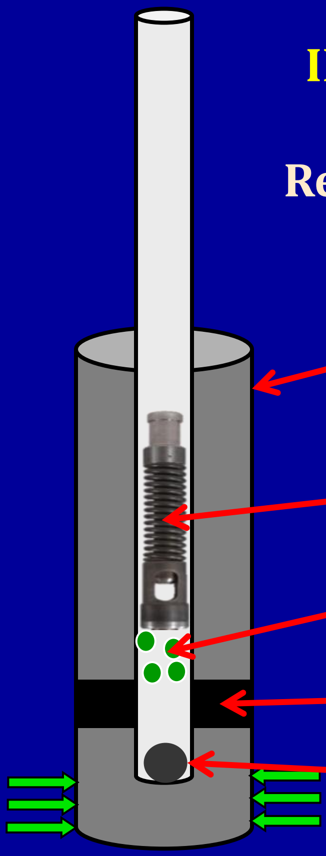
NO PACKER
400 SCF / BBL / 1,000 FT OF LIFT

Example:
400 scf X 10 bbls X 7500 ft / 1000 ft
30,000 scf or 30 mcf
Compare actual to required

Measure actual flow with clear tubing!

WITH PACKER
Higher GLR required.
Typically 2X No Packer.

IF PACKER ALREADY INSTALLED
Remove packer OR .....



Plunger Lift Well Requirements

IS GAS PRESSURE SUFFICIENT ?

LIFT PRESSURE

Lift Pressure >/= 2X Liquid Load

LOAD FACTOR

Liquid Load / Lift Pressure </= 0.5

FOSS AND GAUL

$CP_{req'd} = CP_{min}$ X $\{(A_{ann} + A_{tbg}) / A_{ann}\}$

$CP_{min} = \{SLP + P_p + P_c FV\}$ X $\{1 + D/K\}$

CP = Casing Pressure; SLP = Sales Line Pressure

A_{ann} = Area Annulus; A_{tbg} = Area Tubing

P_p = Pressure req'd to lift just the plunger

P_c = Pressure req'd to lift 1 bbl of fluid and overcome friction

FV = Fluid Volume above the Plunger

K = Constant accounting for gas friction

D = Depth of the Plunger

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

OTHER CONSIDERATIONS

- ✓ Packer ?
- ✓ No holes in tubing
- ✓ Same ID from BHS to Lubricator
- ✓ End of tubing location
- ✓ Control valve trim size
- ✓ Orifice plate trim size
- ✓ Flow meter properly sized
- ✓ Pipeline pressure surge restrictions
- ✓ Dump valves appropriate for surges
- ✓ Clean / dry gas supply available
- ✓ Knowledgeable operator(s) ! ! !

APPLICATIONS AND BENEFITS

Applications and Benefits

TYPICAL APPLICATIONS

GAS WELLS
- ✓ Removal of liquids
- ✓ Reduction of emissions
- ✓ Keeps tubing free of paraffin, salt & scale

OIL WELLS
- ✓ Produce from high GLR wells
- ✓ Conserve formation pressure
- ✓ Control paraffin and hydrates

LOW GAS TO LIQUID RATIO WELLS
- ✓ 2 Stage plunger lift
- ✓ Plunger assisted gas lift
- ✓ Gas assisted plunger lift

TYPICAL BENEFITS

STABILIZES AND IMPROVES PRODUCTION
- ✓ 20% improvement is common
- ✓ Keeps tubing clear of debris
- ✓ Can produce wells to depletion
- ✓ Produces with a low casing pressure

ECONOMICAL
- ✓ Low initial investment
- ✓ Low operating, repair and maintenance costs
- ✓ Reduces chemical cost, venting and swabbing
- ✓ Rig not required for installation
- ✓ Cost of system is unaffected by well depth

GOOD FOR THE ENVIRONMENT
- ✓ Reduces methane emissions and lost gas
- ✓ Operates on solar energy

Primary Purpose
Removal of liquid from gas wells so that gas can flow freely to the surface

Applications and Benefits

TWO STAGE PLUNGER LIFT	GAS ASSISTED PLUNGER LIFT	PLUNGER ASSISTED GAS LIFT
✓ Low GLR, marginal wells	✓ Low GLR wells	✓ Low GLR wells
✓ 200 scf / bbl / 1000 ft	✓ Gas injected to annulus 400 scf / bbl / 1000 ft	✓ Add plunger to intermittent gas lift wells
✓ Two or more plungers in the same well	✓ Short shut-in times	✓ Reduces injected gas requirements (30 % range)
✓ Ideal for wells with packers	✓ +/- 250 Bbls / day possible	✓ Eliminates fall back
✓ Can be used with injection gas	✓ Plunger seal is important	✓ Increases production

Benefits with Telemetry

STABILIZE AND IMPROVE PRODUCTION

- ✓ Allows skilled operator to control many wells
- ✓ Optimize production using real time data and trends
- ✓ Rapid and more accurate troubleshooting

ECONOMICAL

- ✓ Identify & resolve problems before profits are lost
- ✓ Reduce windshield time
- ✓ Reduce equipment repair and maintenance
- ✓ Reduce unplanned well downtime

SAFETY

- ✓ Remote, real time knowledge of well site parameters
- ✓ Remote shut-in of wells when necessary
- ✓ Less drive time (fuel, insurance, maintenance)

Economics

COST ITEMS

- ✓ Check tubing
  - ✓ Drift, broach, pressure check
- ✓ Set bottom hole spring
- ✓ Re-configure well head tree
- ✓ Install lubricator
- ✓ Install control (motor) valve
- ✓ Install pressure transducers

$ 15,000 to $ 25,000

COST ITEMS

- ✓ Establish communication with flow meter and "office"
- ✓ Install plunger lift controller
- ✓ Route clean, dry gas to solenoid
- ✓ Install plunger
- ✓ Swab well if necessary
- ✓ Establish controller settings

Maintain wells natural decline curve. Don't wait till production is lost!

Flow Rate	10 % Change	15 % Change	20 % Change	25 % Change
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

$ 4 / mcf

INSTALLATION AND OPERATION CONSIDERATIONS

Installation Considerations

Standardize Installation!

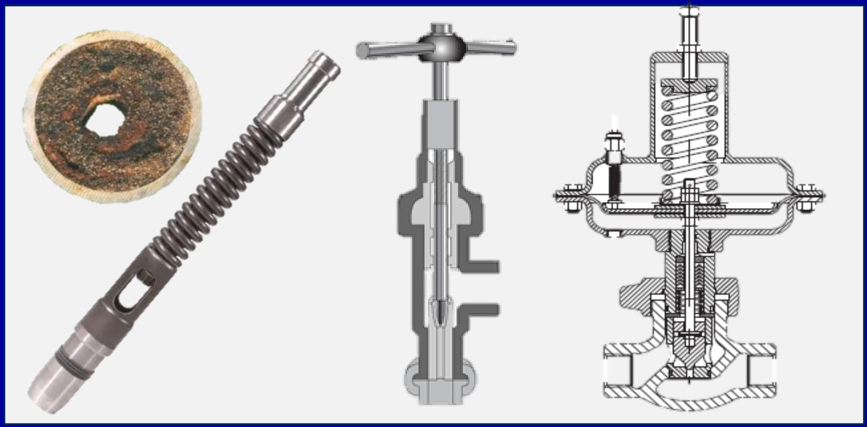
- ✓ Establish a standardized installation process!
- ✓ Dual master valve
- ✓ Dual outlet lubricator
- ✓ Platform to reach lubricator
- ✓ Pressure transducer type, locations
- ✓ Pressure gauge type, locations
- ✓ Solenoid supply – clean / dry gas!
- ✓ Control valve type. Trim size, materials.
- ✓ Ball valve model number & locations
- ✓ Hammer union locations
- ✓ Flow meter communication - trench or radio?
- ✓ Communications with office – spread spectrum radio or cell phone data radio
- ✓ Controller location and attachment method
- ✓ Lightening suppression
- ✓ Emergency shut off
- ✓ Sand cut probe

WELL HEAD

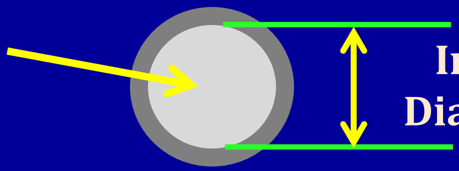
- ✓ Well head ID compatible with tubing ID
- ✓ Remove unnecessary WH components
  - Minimize height of wellhead tree
- ✓ Eliminate gaps and ID inconsistencies
- ✓ Sleeve wellhead if necessary
  - Maintain same ID – BHS to Lubricator

Installation Considerations

Minimize Restrictions !



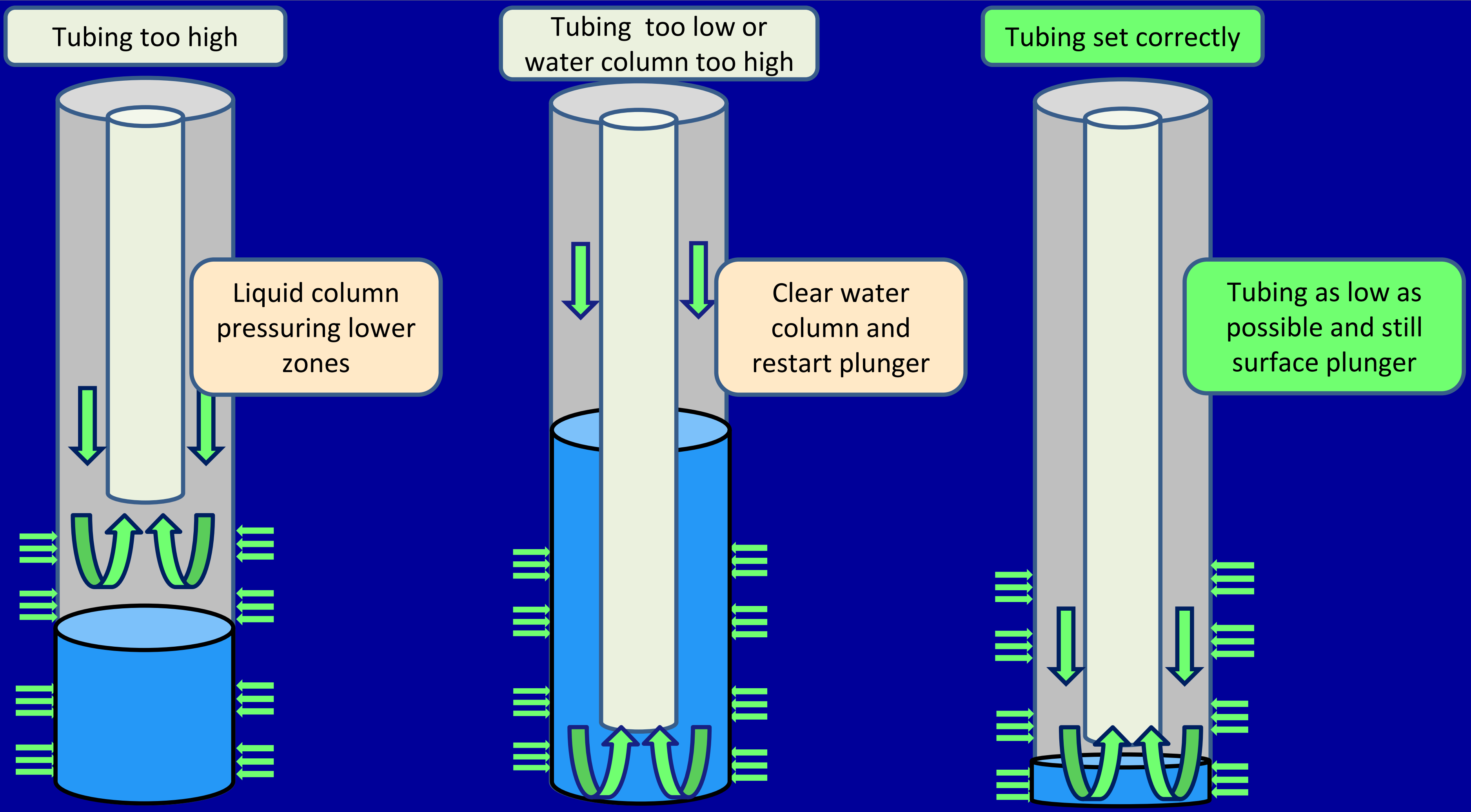
- ✓ Scale, Paraffin – Drift and broach tubing
- ✓ Bottom hole spring holddown – size, debris
- ✓ Motor valve trim – full port opening
- ✓ Orifice plate at flow meter
- ✓ Well head – Sleeve if needed
- ✓ Chokes



Diameter	Area	% Difference
7/8 inch	0.601 inch^2	0 %
1 inch	0.785 inch^2	30.6 %
1 ¼ inch	1.227 inch^2	104.2 %
1 ½ inch	1.767 inch^2	194.0 %

Installation Considerations

End of Tubing Location - Vertical Well



Installation Considerations

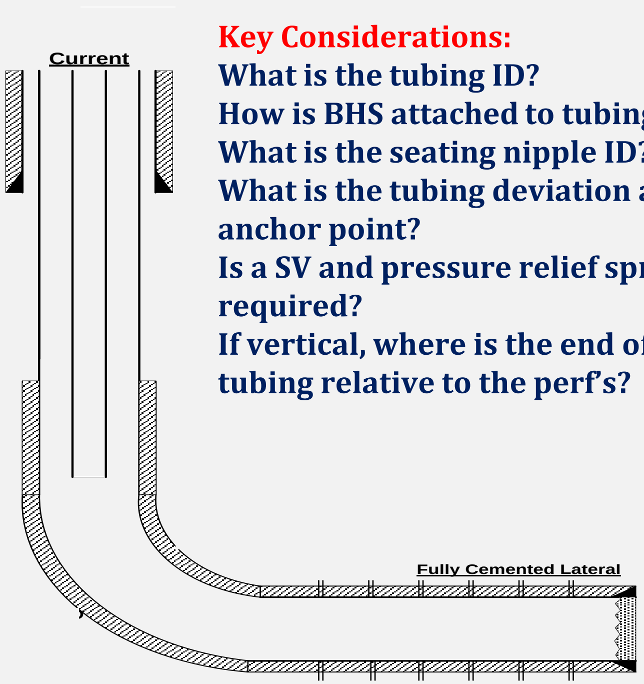
Bottom Hole Spring Location – Horizontal Well

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
7539	7313.41	834.27	-333.82	58.9	10.6

Bottom Hole Spring Location - Deviation

45 to 50 degree typical

SPE 147225 – Analysis of Plunger Lift Applications in the Marcellus Shale



Key Considerations:

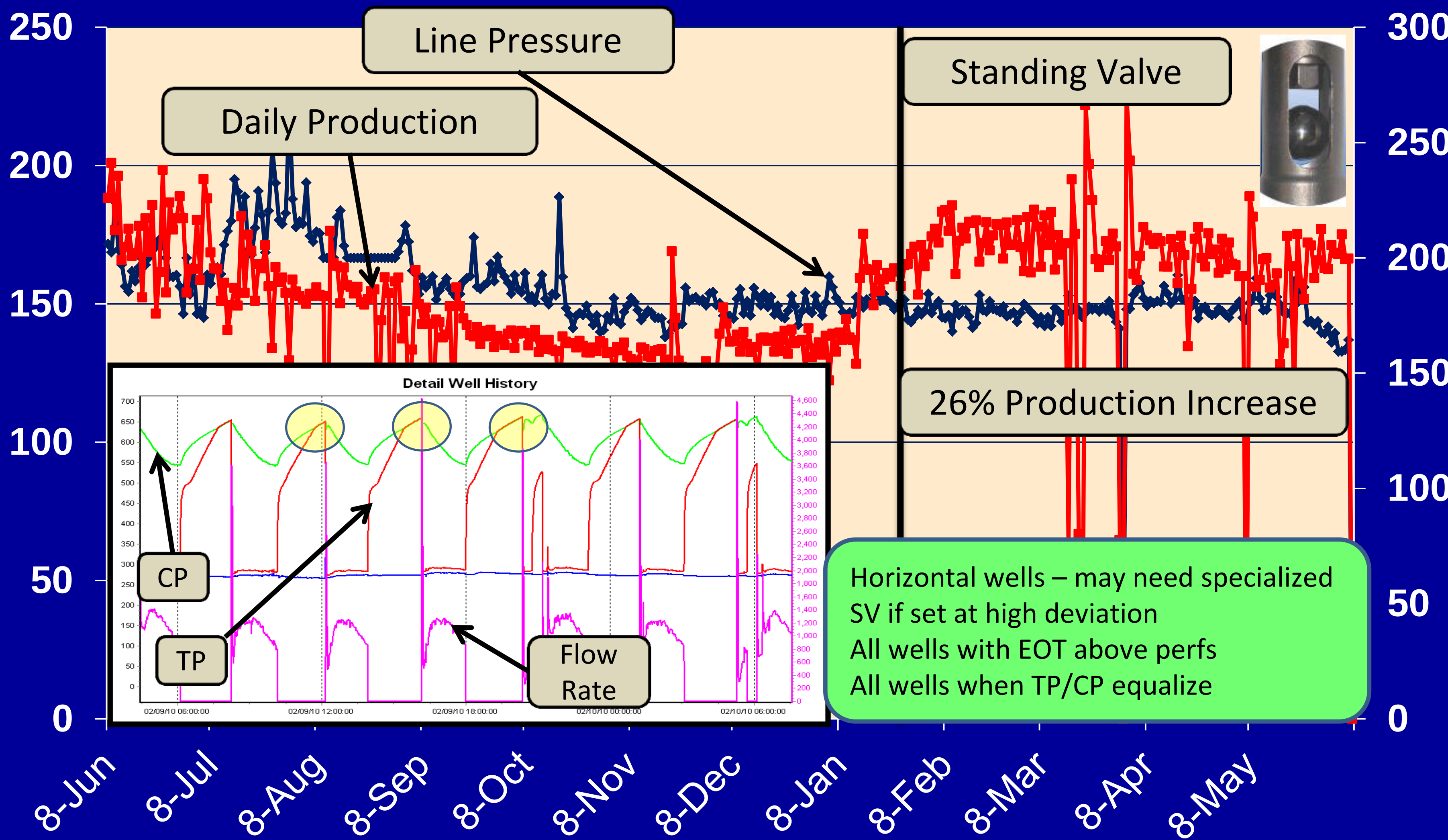
What is the tubing ID?
How is BHS attached to tubing?
What is the seating nipple ID?
What is the tubing deviation at the anchor point?
Is a SV and pressure relief spring required?
If vertical, where is the end of tubing relative to the perf's?

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.

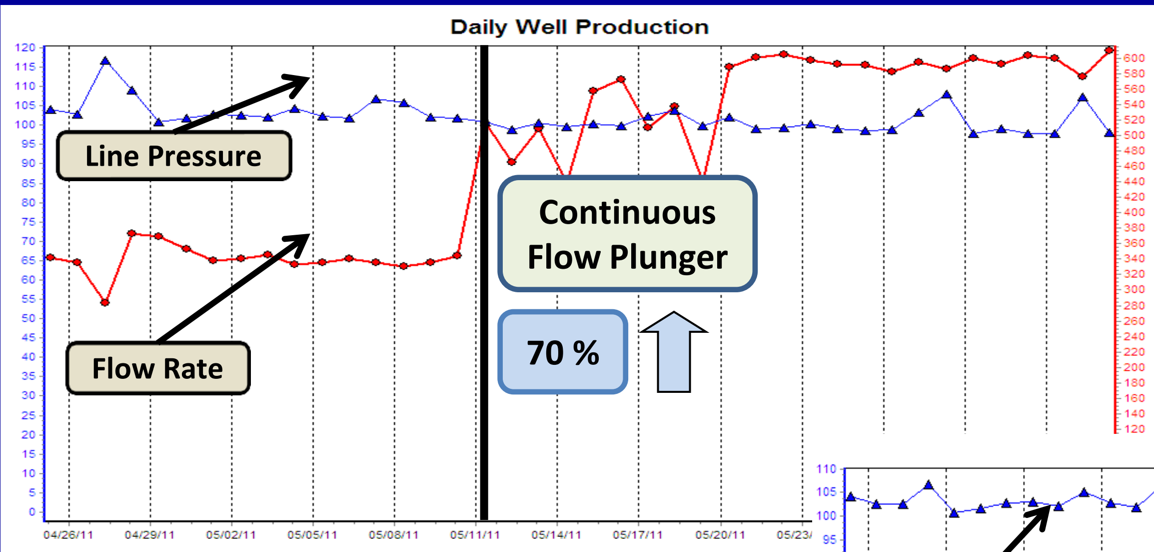
Installation Considerations

Standing Valve

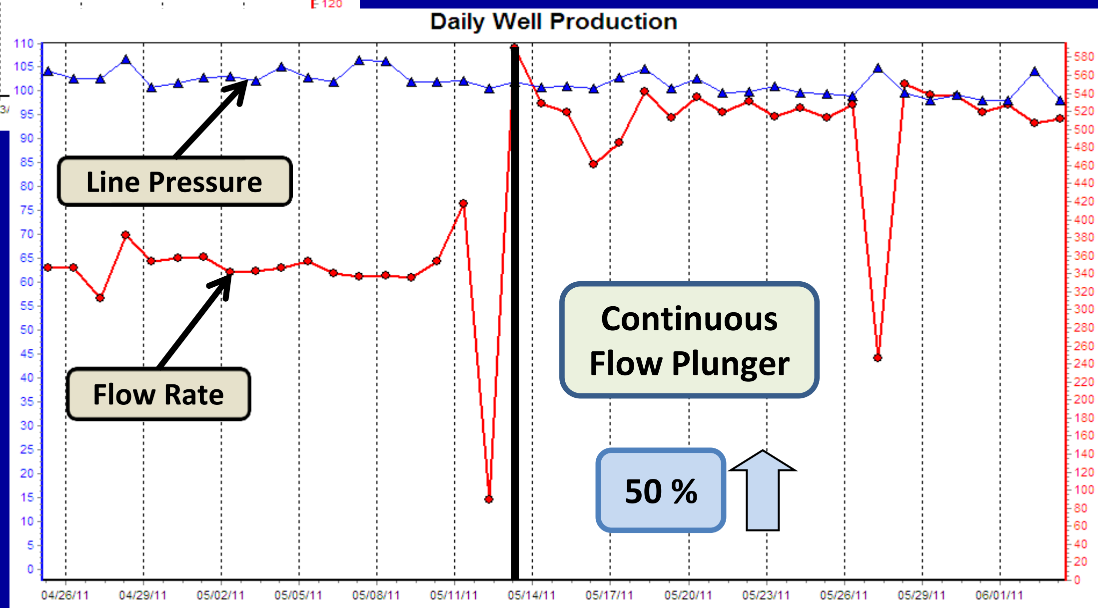


Installation Considerations

Plunger Selection



Use the **right plunger** for the **well conditions**



Replace **worn plungers** **BEFORE** production declines

Operation Considerations

Algorithm Selection

Operate at the maximum number of cycles to generate the lowest average flowing bottom hole pressure

Open Conditions

(After fall time elapses)

Open at minimum pressure required to surface plunger at desired plunger velocity

- Time = set point
- Tubing pressure = set point
- Casing pressure = set point
- Tubing/Casing = set point
- Tubing – Line = set point
- Lift pressure = set point
- Lift pressure = Foss and Gaul
  = % of Foss and Gaul
- Load Factor = Set point

Load Factor = Liquid Load / Lift Pressure

Close Conditions

(After plunger surfaces)

Maximize production while allowing the designed quantity of liquid to enter tubing on every cycle

- Time = set point
- Tubing pressure = set point
- Casing pressure = set point
- Flow Rate = set point
  = Critical flow
  = % of critical

Operation Considerations

Preventative Maintenance

Method
- Who? What? When? How to track?

Typical "checks"
- Plunger
  - When to replace? How do you know?
- Lubricator
  - Spring, catcher, connection to WH
- Bottom hole spring
  - Debris, spring, seal
- Motor valve
  - Trim, gas supply if utilized
- Battery / Solar panel
- Valves - grease
- Arrival sensor & cable – no misses!
- Tubing – no obstructions, no holes
- Flow meter calibration

Other

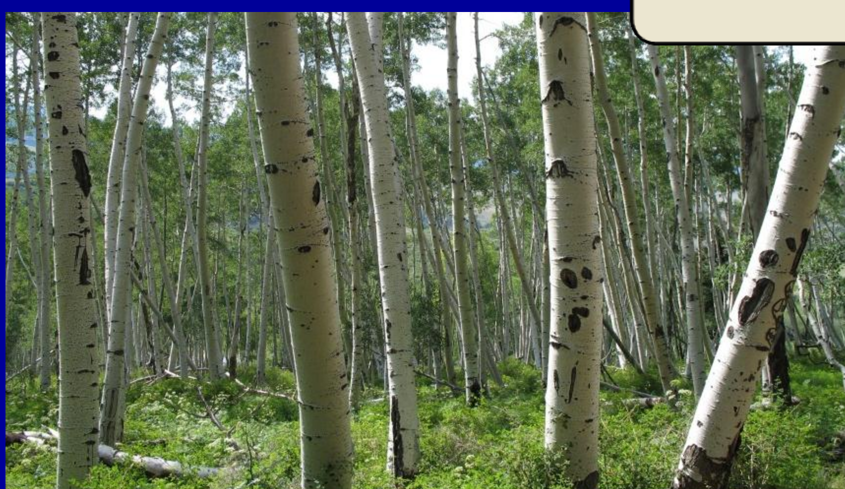
Organizational structure
- In house optimizers?
- Field operator responsibilities?

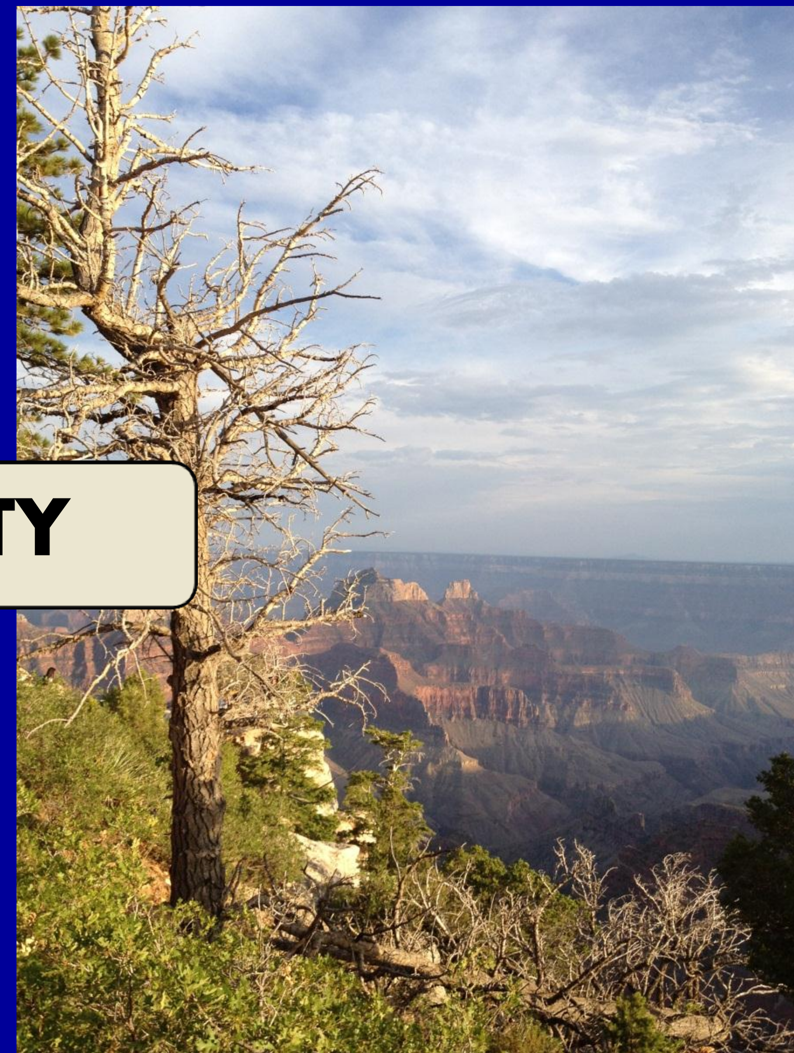
Training
- Who? How often? Track learning!
- Basic plunger lift principles
- Plunger lift equipment
- Optimization of wells
- Troubleshooting
- Controller settings
- Problem solving process

Initial well lineout
- Who?

Remote monitor and optimize
- In house? 3rd Party?

SAFETY





Arrive at site safely !

- In 2011, more than 2 out of every 5 fatal workplace incidents were transportation accidents

- Four primary causes of O&G related transportation accidents
  - Ignoring the speed limit
  - Using a cell phone while driving

    About 80% of people involved in traffic accidents are distracted
  - Not wearing a seat belt

    63 % of people killed in traffic accidents were not wearing seat belts
  - Lack of rest

    Tired drivers involved in 4,000 road crashes in Texas in 2010

Safety

Appropriate Training!
Hard Hat, Steel Toe Boots
Flame retardant clothing
Safety glasses
H2S monitor

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 (electrical, mechanical, pressure, height, etc)
- Determine necessary actions to eliminate, control, or minimize hazards
- Each safe job procedure or action must correspond to the job steps & identified hazards

What Is Hydrogen Sulfide?
Hydrogen sulfide is a naturally occurring gas that is produced along with natural gas and crude oil. It can be fatal if breathed!

Hydrogen Sulfide (H_2S)

- 1 ppm Can be smelled
- 10 ppm 8-hour exposure permitted
- 200 ppm Numbs smell rapidly and burns eyes, throat
- 500 ppm Loss of reasoning and balance. Respiratory disturbance in 2 – 15 minutes
- 700 ppm Loss of consciousness quickly.
- 1,000 ppm Unconsciousness occurs at once.

Safety

Serious Injuries

- Pressure traps (hydrates, sand, scale)
- Lubricator cap off, pressure trap under plunger
- Open master valve, hammer unions not secure
- Installing well head with underrated equipment
- **High plunger velocity – especially when venting to tanks**
- Compressed lubricator springs
- Removing cap, cracking open control valve
- Pressure gauges are not always right

Alberta Workplace Health and Safety Bulletin
May 2007

Injury

- An ice plug in the lubricator released and struck a worker in the head

Contributing factors (partial list):

- Ice build up in the lubricator assembly
- Poor procedures in identifying potential hazards
- Lack of operator training in safe work practices for the use of this equipment
- Removing lubricator cap with contained pressure
- Ice build up in the spring housing
- Paraffin, wax, sand and hydrates build up in the tubing string
- Poorly designed springs or stops
- No methanol injection or heat trace to keep ice and hydrates from forming
- 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

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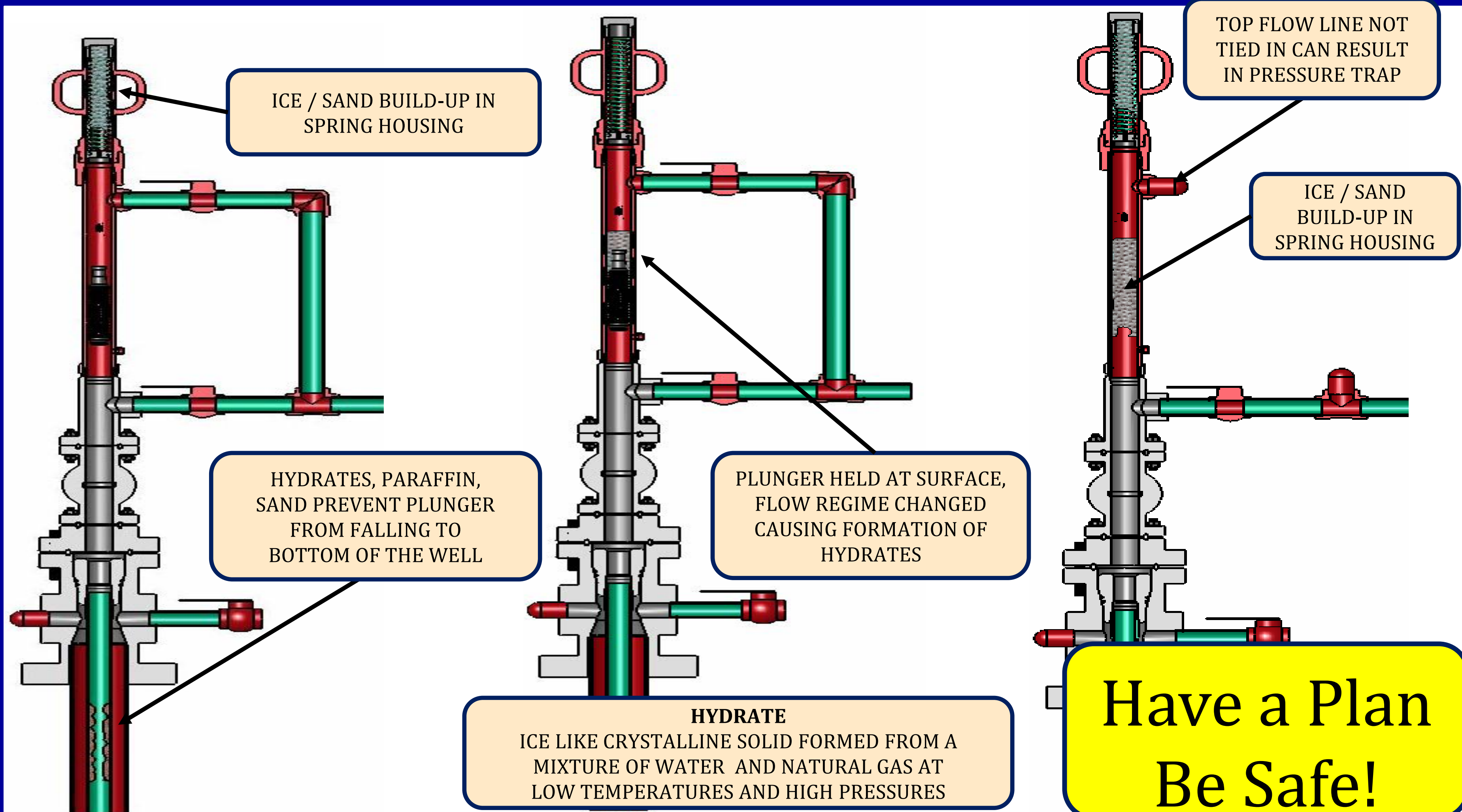
May 2007



Linkedin Group

"Plunger Lifted Gas Wells"

ADDENDUM

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 psi/ft X 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

2 3/8" tubing (1.995" ID)

CP-TP (psi)	Liquid Volume (bbls ; SG = 1)	Liquid Height (solid column)	Liquid Height (80% gaseous)
10	0.089	23 ft	115 ft
20	0.178	46 ft	231 ft
30	0.268	69 ft	346 ft
40	0.357	92 ft	462 ft
50	0.446	115 ft	577 ft
60	0.535	138 ft	692 ft
70	0.625	161 ft	808 ft
80	0.714	185 ft	923 ft
90	0.803	208 ft	1039 ft
100	0.892	231 ft	1154 ft
125	1.115	288 ft	1443 ft
150	1.338	346 ft	1732 ft
175	1.562	404 ft	2020 ft
200	3.569	923 ft	4618 ft

2 7/8" tubing (2.441" ID)

CP-TP (psi)	Liquid Volume (bbls ; SG = 1)	Liquid Height (solid column)	Liquid Height (80% gaseous)
10	0.133	23 ft	115 ft
20	0.267	46 ft	231 ft
30	0.400	69 ft	346 ft
40	0.534	92 ft	462 ft
50	0.668	115 ft	577 ft
60	0.801	138 ft	693 ft
70	0.925	162 ft	808 ft
80	1.068	185 ft	924 ft
90	1.202	208 ft	1039 ft
100	1.336	231 ft	1154 ft
125	1.670	289 ft	1443 ft
150	2.003	346 ft	1732 ft
175	2.338	404 ft	2020 ft
200	5.343	923 ft	4616 ft

Sufficient Volume and Pressure

Sufficient Gas Volume

- No Packer
  - 400 scf / bbl / 1000 ft of lift
- Packer
  - 2,000 scf / bbl / 1000 ft of lift

Sufficient Gas Pressure

- Casing Pressure at least 1.5 X line pressure
- Lift Pressure at least 2 X greater than fluid load
- See Foss and Gaul requirements

Casing Pressure Required

Foss and Gaul (CP Required to Lift Plunger)

- $CP_{req'd} = CP_{min} \times \{(A_{ann} + A_{tbg}) / A_{ann}\}$
- $CP_{min} = \{SLP + P_p + P_c FV\} \times \{1 + D/K\}$

Tubing	K	Pc
2 3/8	33,500	165
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- 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

Critical Flow Rate

Critical Flow Rate (Coleman, P_f Less Than 1,000 psi)

- $CV_{water} = 4.434 \text{ X } [\{(67 - 0.0031P_f)^{1/4}\} / \{(0.0031P_f)^{1/2}\}]$
- $CV_{condensate} = 3.369 \text{ X } [\{(45 - 0.0031P_f)^{1/4}\} / \{(0.0031P_f)^{1/2}\}]$
- $FR = CV \text{ X } [pi \text{ X } (ID/2)^2] \text{ X } (1 \text{ ft}/144 \text{ in}^2) \text{ X } 86{,}400 \text{ sec/day}$
- 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%

Standard Cubic Foot

$SCF = ACF \times P_f/P_s \times T_s/T_f$

- SCF = Standard Cubic Foot of gas
  - Volume of gas contained in $1ft^3$ at 60^oF and 14.7 psi
- ACF = Actual or Measured Cubic Foot
- P_f = Flowing pressure (psi); P_s = 14.7 psi
- T_f = Flowing temperature (^oR)
- T_s = Standard temperature (516.67^oR)
- $^oR = {}^oF + 459.67$

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