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Multi-Stage Plunger Lift: Case Histories

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Abstract

Liquid loading in deep wells with low BHFP affects the production capacity of several wells in the S. Oklahoma district area. Low producing rates, low BHPs and difficult mechanical configurations are typical conditions for wells in the area.

Conventional plunger lifts, pumping units, chemical foamers and capillary strings have been utilized to keep these wells unloaded.

This presentation will cover case histories where the multi-stage plunger lift tool is proven as a more efficient method to unload fluids in wells with low GLRs and FBHPs.

Southern Oklahoma District Overview

- Eight operating fields.
- Producing wells ranging from 5,000ft to 22,000ft deep.
- Operate wells with angles of inclination>25^{o} and dog leg severities up to 6^{o}/100ft.
- High number of mature wells with low GLR's and low FBHPs.
- Unconventional mechanical configurations: Tapered strings, 3-1/2" monobore completions.

Conventional Lift Considerations

Traditional means of unloading low BHP wells have consisted of rod pump and plunger lift.

Rod pumping applications require high OEM and upfront capital expense.

Plunger lift applications require low OEM, low CAPEX, but need proper mechanical configuration to run efficiently. Not always successful in low GLR wells.

These two examples have created the need for a modified lift assembly that will reduce OEM and CAPEX but have results similar to a rod pumped application.

As a result, COI has initiated a program to test viability of multi-stage plunger lift application in moderate to severe operating environments.

Introduction

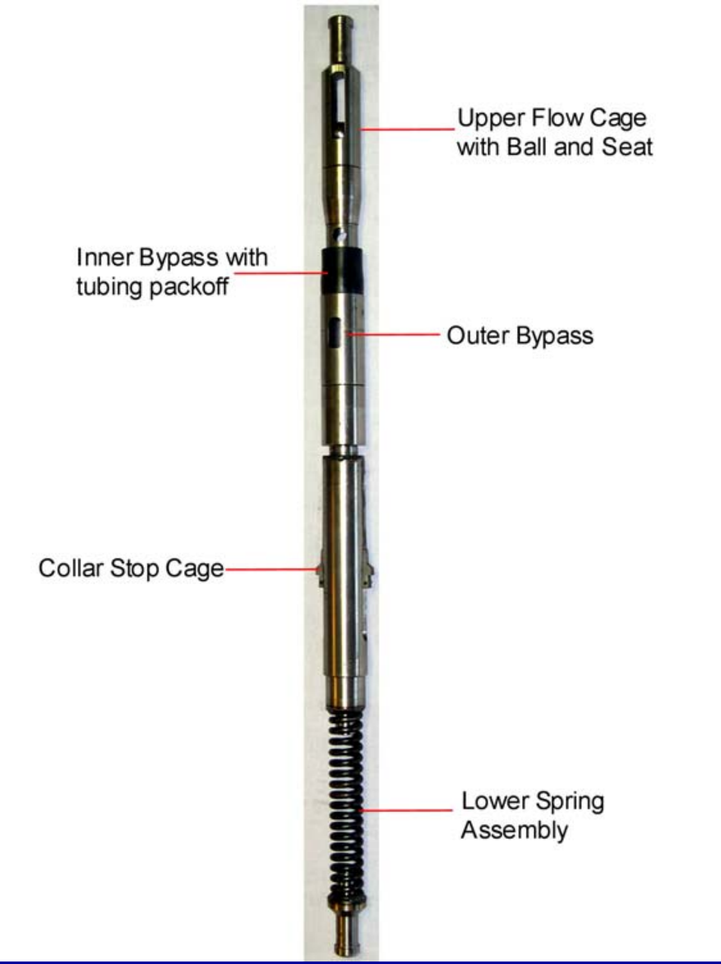
Tool Overview:

- Modified plunger lift system.
- Moves part of the well’s energy under each column.
- Staging the well reduces the need for high flowing BHPs as hydrostatic pressures are minimized by creating two “operating chambers”.
- Uses part of the head gas as energy to lift fluids.
- Reduces required shut-in times to lift a liquid load.

Introduction

Tool Applications:

- Slimhole operations
- Packer wells
- Marginal wells
- Liner Wells
- Tapered string
- Open hole completions



How does it work?

Case Histories: Well A

Well overview:

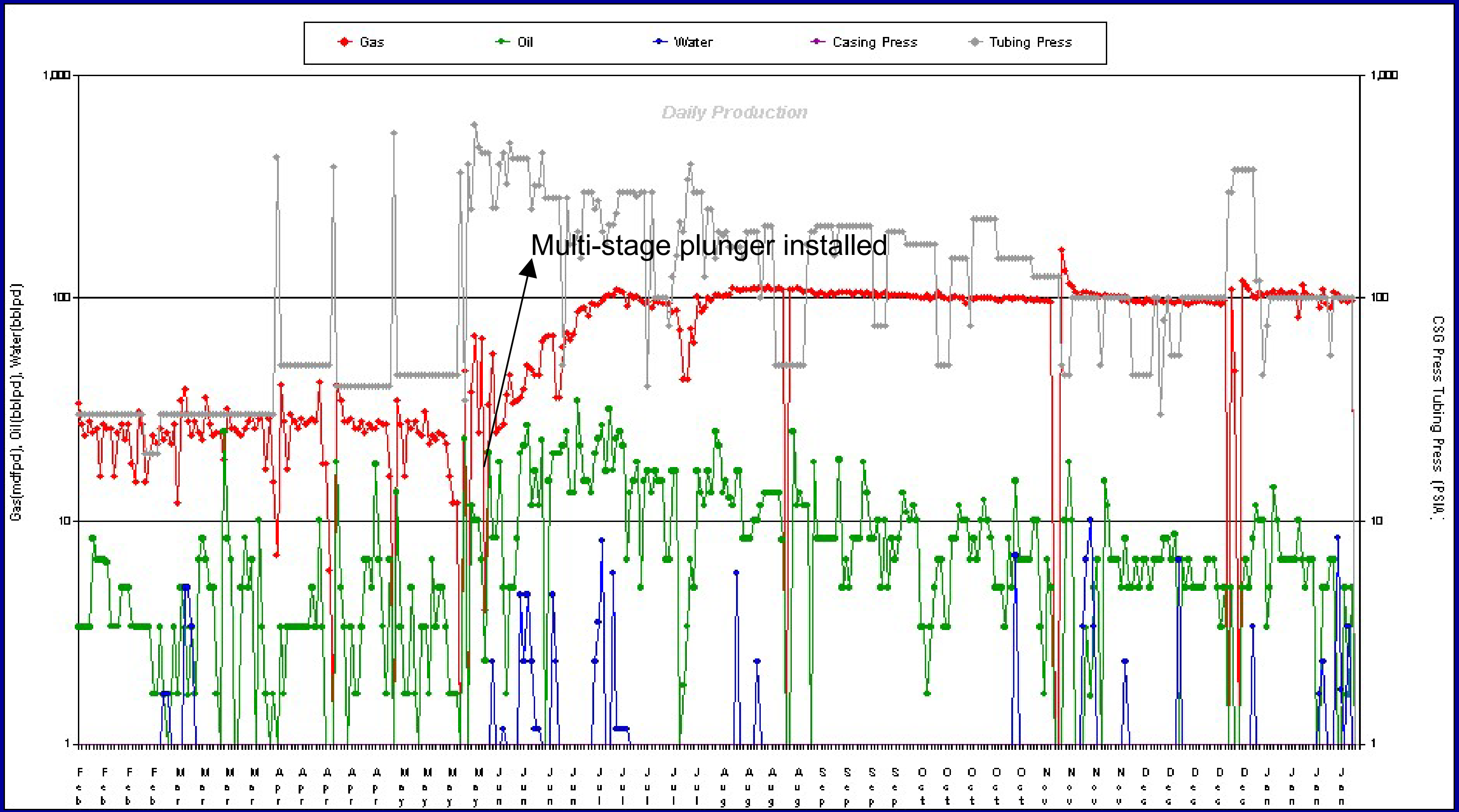
- High-angle wellbore: 46^{o} angle at 8,312’.
- Well producing at 30MCFPD and 7BOPD. SI/cycling every 20 days.
- Producing up 2-3/8” tubing with a FTP of 45psi. No backside pressure (production packer set at 8,650’) SN at 8,620’.
- Perforated interval: 8,894’- 9,710’ OA.
- No artificial lift previously installed.
- Low line pressure: 25psi

Case Histories: Well A

Tool implementation:

- Stage tool set at 6,844’ (70% total tubing string depth).
- 85MCFPD and 3BOPD incremental production observed after installing tool.
- Total installation cost: $9.9M
- Stabilized production, reduced SI/Cycling time.

Production summary: Well A



Case Histories: Well B

Well overview:

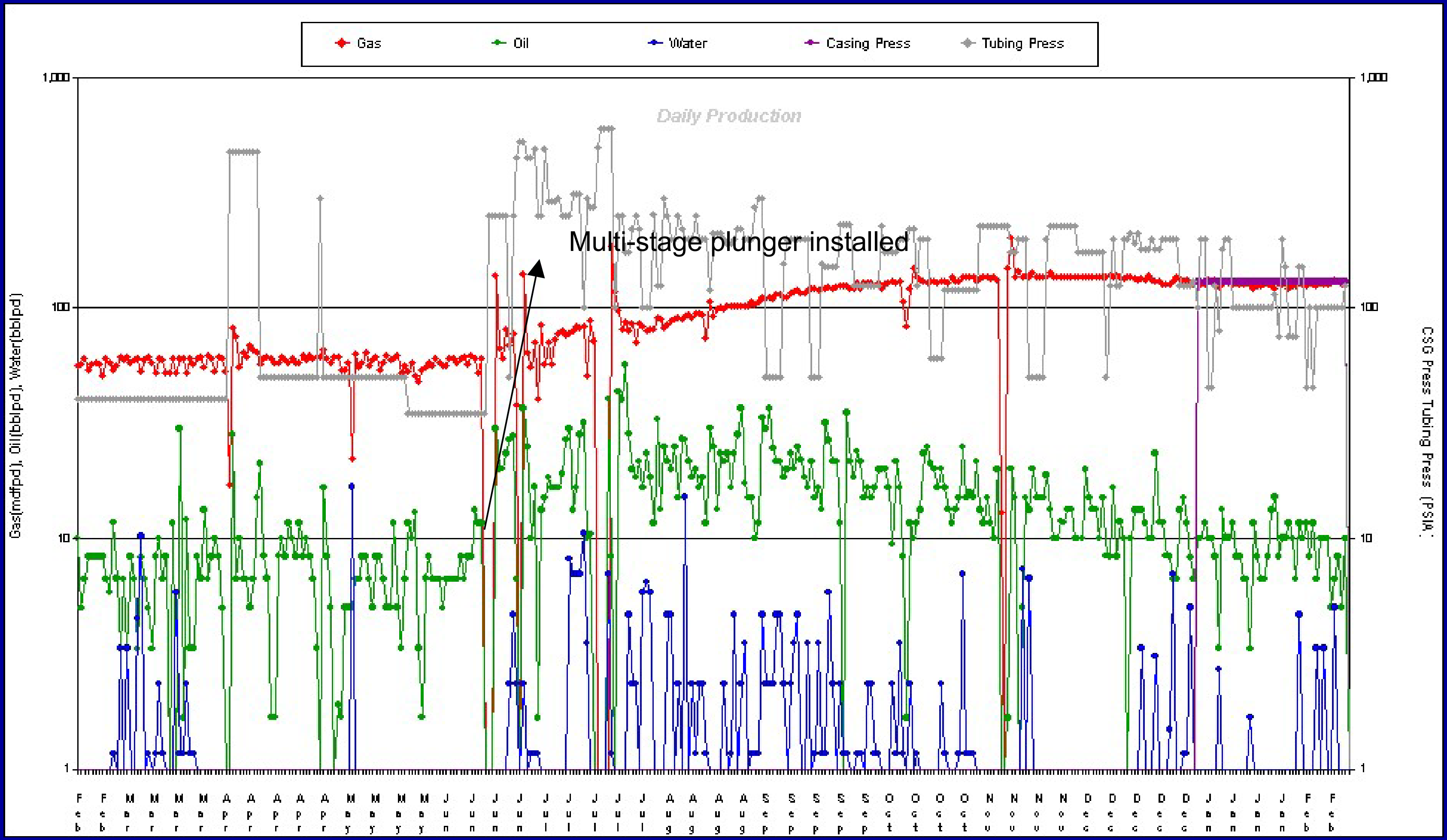
- Deviated wellbore with a 57^{o} angle of deviation at 8,575'.
- Well producing at 60MCFPD and 7BOPD with minimum SI/cycling time.
- Producing up 2-3/8" tubing with a packer set at 8,200'. Flowing tubing pressure 50psi.
- Open hole completion. 7-5/8" casing set at 8,565'. EOH at 12,169' (8,688' TVD).
- Line pressure: 30psi

Case Histories: Well B

Tool implementation

- Stage tool set at 6,844' (74% total tubing string depth), with a deviation angle of 32^{o} and a 4^{o}/ft dog leg severity at setting depth.
- Incremental production of 80MCFPD and 4BOPD observed after installing the tool.
- Total installation cost: $12.2M.

Production summary: Well B



Case Histories: Well C

Well overview:

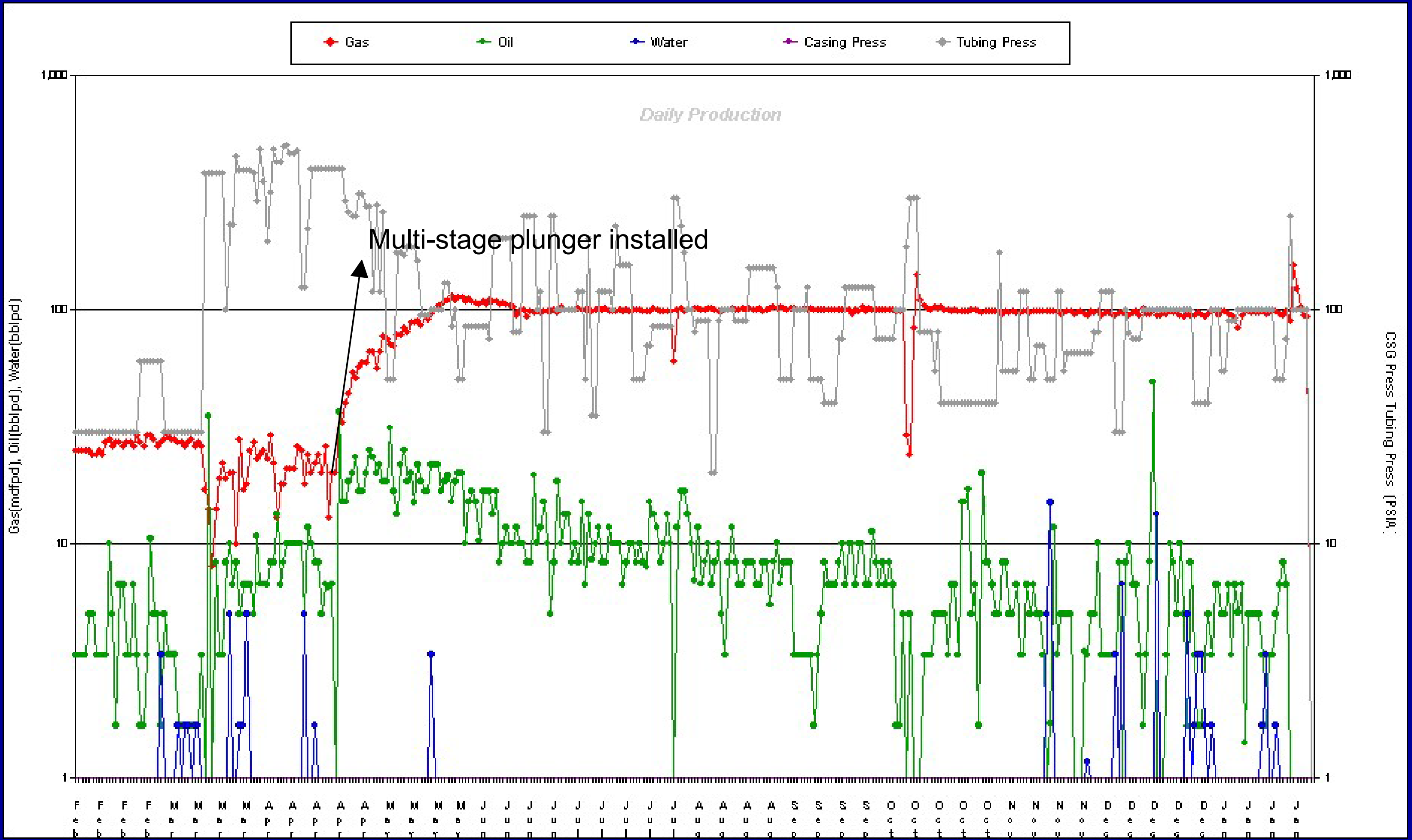
- Well producing at 40MCFPD and 8BOPD with no SI/cycling time.
- Producing up 2-3/8” tubing with a packer set at 7,300’. EOT at 7,331’. Flowing tubing pressure 50psi.
- Cased hole with perforations from 7,360’ – 7,816’ (OA).
- No artificial lift previously installed.
- Line pressure: 30psi.

Case Histories: Well C

Tool implementation:

- Stage tool set at 5,414’ (74% total tubing string depth).
- Production increase of 60MCFPD and 2BOPD observed after installing tool.
- Total installation cost: $11.1M
- Stabilized production, no SI/Cycling time required.

Production summary: Well C



Case Histories: Well D

Well overview:

- Well producing at 40MCFPD and 9BOPD and 2BWPD.
- Well's observed GLR: 3600 scf/bbl
- Deviated wellbore with a deviation angle of 53^{o} at 8,831'(casing depth).
- Open hole completion. 7-5/8" casing set at 8,831'. EOH at 12,730' (9,053' TVD).
- Producing up 2-7/8" tubing with EOT at 8,541'.
- 300psi tubing pressure with backside open (400psi casing pressure).
- Line pressure: 25psi

Case Histories: Well D

Tool implementation:

- Stage tool set at 6,781’(80% from total tubing depth). A deviation angle of 4^{o} and a dog leg severity of 2^{o}/ft at setting depth.
- Small production increase observed after installing the tool (10MCFPD increase).
- Total installation costs: $5.9M.
- No decrease in production downtime observed after installing the tool.

Production Summary: Well D

Case Histories: Well E

Well Overview:

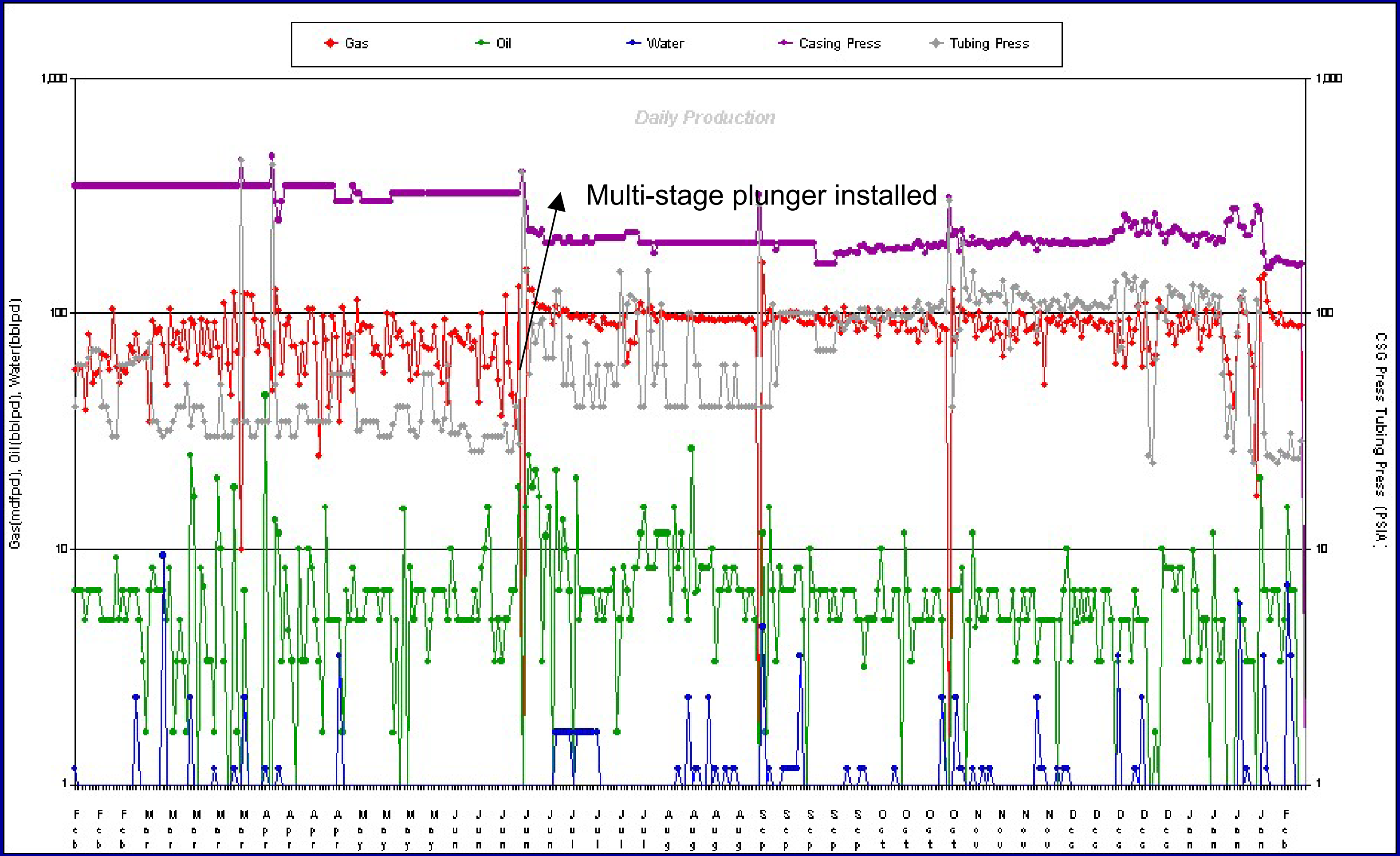
- Well producing at 70MCFPD and 6BOPD.
- Unsuccessful plunger lift installation
- Deviated wellbore with a deviation angle of 43^o at 6,695ft.
- Open hole completion. 7-5/8” casing set at 6,695’. EOH at 10,315’ (7,645’ TVD).
- Producing up 2-7/8” tubing with EOT at 6,646’.
- 40psi tubing pressure with backside open (325psi casing pressure).
- Line pressure: 35psi.

Case Histories: Well E

Tool implementation:

- Stage tool set at 4,667’ (70% from total tubing depth).
- Small production increase observed after installing the tool (20MCFE increase).
- Total installation costs: $12.5M
- Production downtime observed after installing the tool.

Production Summary: Well E



Project Results

- 32 multi-stage plunger installations in the Southern Oklahoma District (60% success rate).
- An average daily production increase of 45MCFE was observed from successful multi-stage plunger lift installations.
- Extended life of marginal, low pressure wells.
- Consistent production rates were attained. SI/cycling time is significantly reduced.
- Other applications are currently being evaluated: 3-1/2" monobore completions, tapered tubing strings, etc.
- Effectively there is no significant increase in OPEX after installation. Increase noted is due to chemical cost for incremental fluid production.

Summary Observations

- Wells producing without backside pressure showed the best results using the multi-stage tool.
- A minimum GLR of 3000 scf/bbl is recommended.
- Wells with 4000<GLR<8000 scf/bbl showed the highest production increase after installation.
- Depth of collar stop for second stage is dependent upon well's GLR.
- Usually run second collar stop 70% of total tubing string length.
- Open hole applications showed the least benefit from running the multi-stage tool.
- High tool efficiency was observed in deviated wellbores.

Summary Observations

When to chose a multi-stage tool?

	Multi-Stage PL	Conventional PL	Pumping Unit
Packer	X		
Deviated wellbore	X		
Open hole completions	X		
GLR>3000 & depths<7000’		X	
GLR>3000 & depths >7000’	X		
GLR<3000 & depths <10,000’			X
Cycling time>24hrs	X		