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# Solving Gas Interference Issues with Sucker Rod Pumps in the Permian Basin

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# Agenda

- Introduction
- Theory
  - Gas Separation with Sucker Rod Pumps
  - Control of Horizontal Wells
  - Backpressure
- Results
- Conclusions

# Introduction

- Sucker rod pumps (SRP) are the most commonly used form of artificial lift within Oxy, ~10,000 installs worldwide
  - Conventional production
  - Water, $CO_2$, and steam flood
  - Unconventional shale
- For unconventional wells, gas handling is a significant challenge
  - Reduces pump efficiency
  - Increases power consumption
  - Reduces equipment life
  - Commonly associated with high fluid levels

# Theory

# Gas Separation with Sucker Rod Pumps

- Most effective solution is to locate pump intake below producing zone
- Annulus acts as a gravity-driven separator
- Not feasible for wells with high solids production, insufficient rathole, or horizontal wells

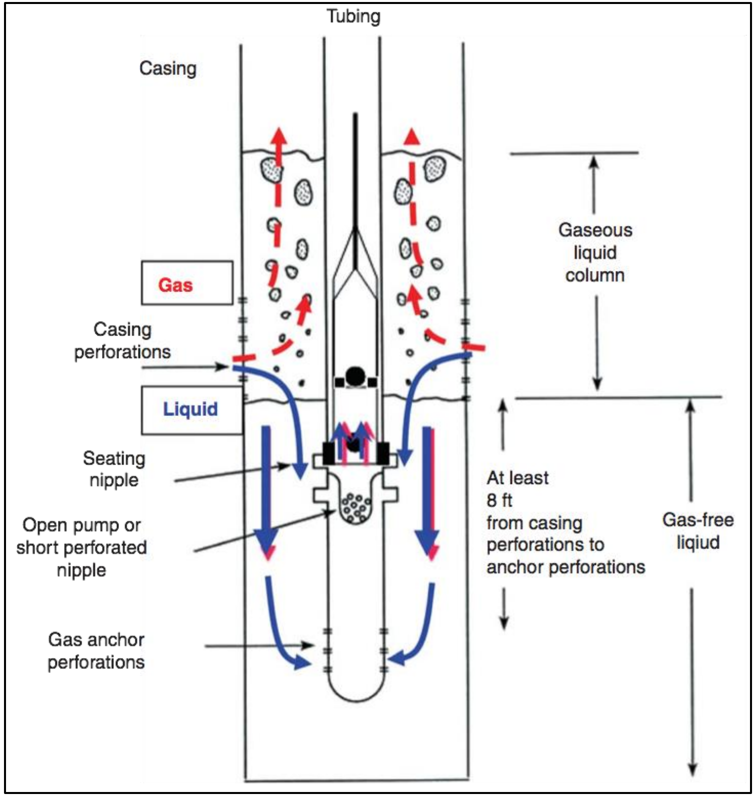



**Figure 1 – Natural gas separator (McCoy et al. 2015)**

# Gas Separation with Sucker Rod Pumps

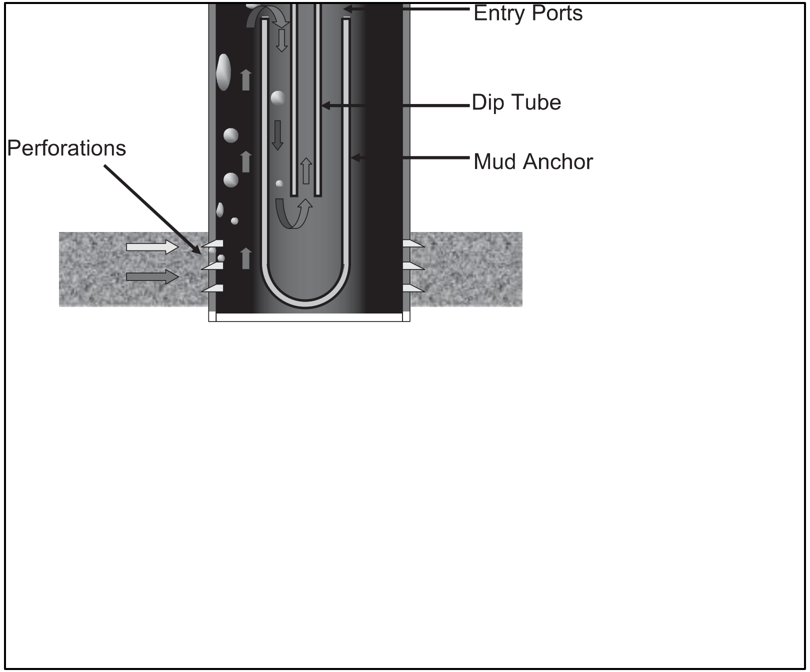



**Figure 2 – Typical downhole gas separator (Bohorquez et al. 2009)**

- Gas separator may be installed as part of the tubing
- Separation space is created by flow of fluid from the top of the separator down to the dip tube

# Gas Separation with Sucker Rod Pumps

- University of Texas (UT) has performed significant testing of these separators (Bohorquez et al. 2009)
- Results indicated adequate separation occurs at liquid velocities below 6 in./sec for 0.25 in. diameter bubbles
  - o Above this velocity, gas bubbles reach the end of the dip tube and are drawn into the pump

# Gas Separation with Sucker Rod Pumps

- Field experience has shown that many wells experience gas interference well below the 6 in./sec determined under lab conditions
  - UT testing was with water/air at 5 to 15 psi
  - Field conditions are at varying water cuts and inlet pressures
- Haberman and Morton (1953) published results of bubble rise velocity in a variety of fluids
  - Tap water results compared favorably with UT, 6.3 to 7.87 in./sec
  - Velocity in mineral oil was significantly lower, only 1.57 in./sec
    - Such a bubble rise velocity reduces the capacity of our most common separator from 305 to 80 bbl/D

# Control of Horizontal Wells

- Flow from horizontal wells is inconsistent, with alternating slugs of liquid and gas of varying frequency and duration
  - These types of wells are difficult to control with conventional pump-off controllers (POCs) as their idle time is fixed
- A variable speed drive (VSD) can continuously adjust pump speed to match inflow
  - Slows during gas-dominant flow to reduce wear and stress on rods and downhole pump
  - Increases speed when liquid-dominant flow resumes to maximize production

# Backpressure

- A common misconception is increasing backpressure can reduce gas interference at the pump
  - However, increasing surface backpressure only influence pressure in the tubing <u>above</u> the pump
  - Pressure inside the pump chamber is only affected by the fluid above pump (FAP) in the annulus

# Backpressure

- Increasing backpressure has many negative affects on the SRP system
  - Increases rod stress
  - Increases pumping unit structure and gearbox loading
  - Increases pump slippage (Patterson et al. 2000)
  - Increases rod stretch, decreasing downhole pump stroke
  - Increases pump horsepower and electrical consumption

# Results

# Separator Performance with Varying Water Cut

| | Well Q | Well R |
|---|---|---|
| Water cut (%) | 70 | 30 |
| Separator capacity (bbl/D) | 600 | 600 |
| Pump displacement (bbl/D) | 460 | 220 |
| Average liquid production (bbl/D) | 390 | 82 |
| Pump efficiency (%) | 85 | 37 |

# Separator Performance with Varying Water Cut

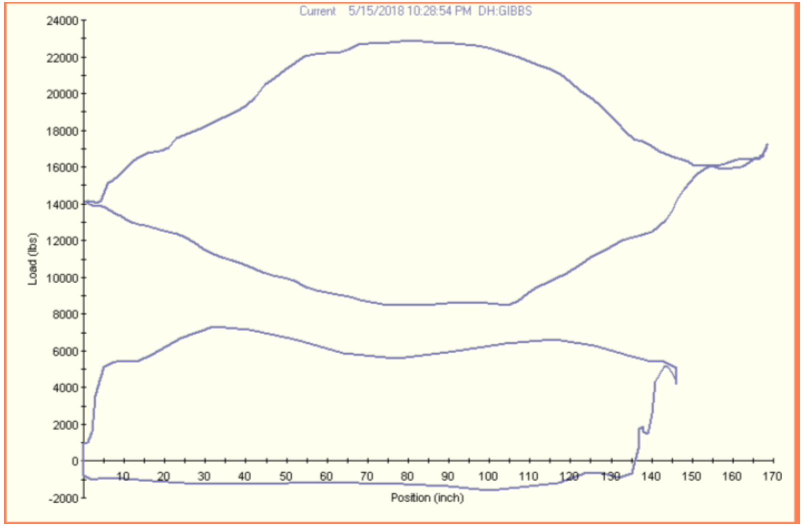



**Figure 3 – Well Q dynamometer card**

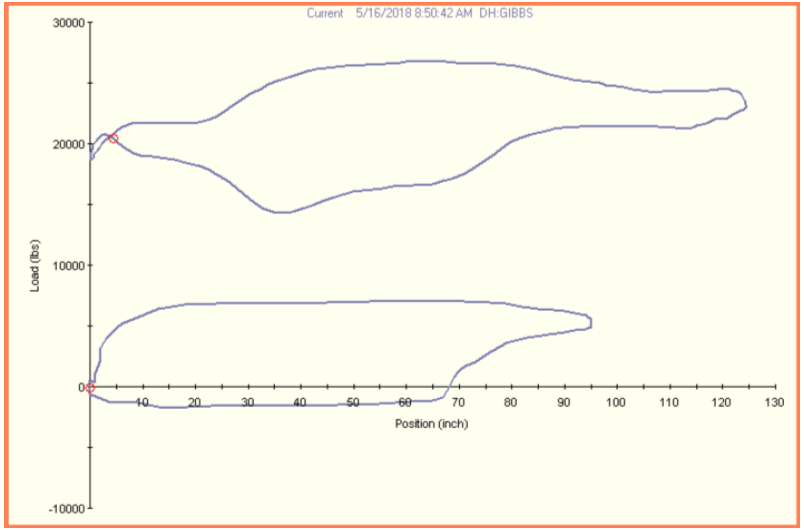
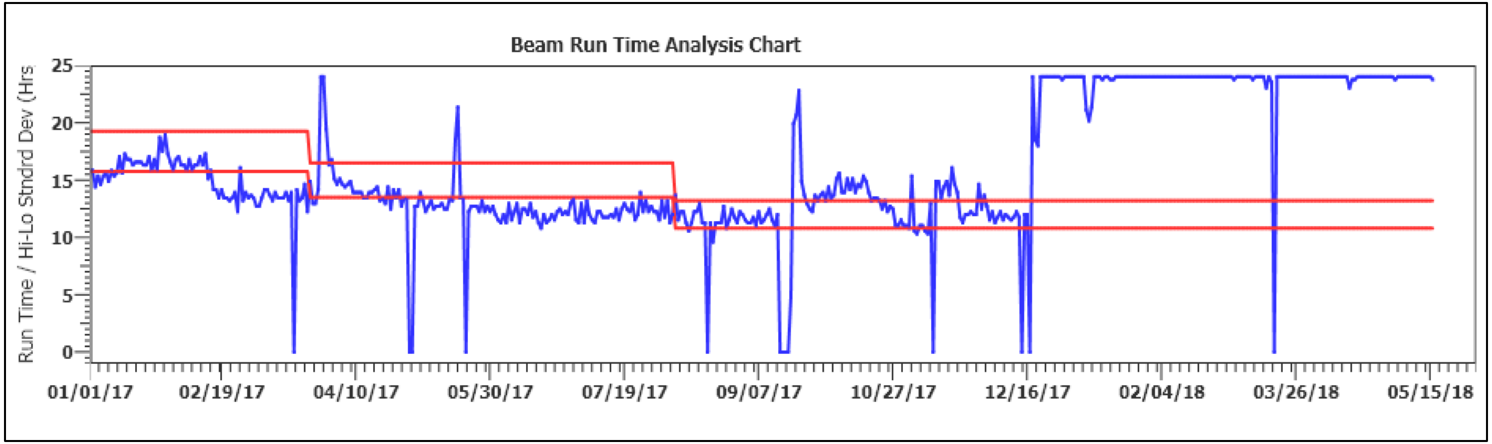


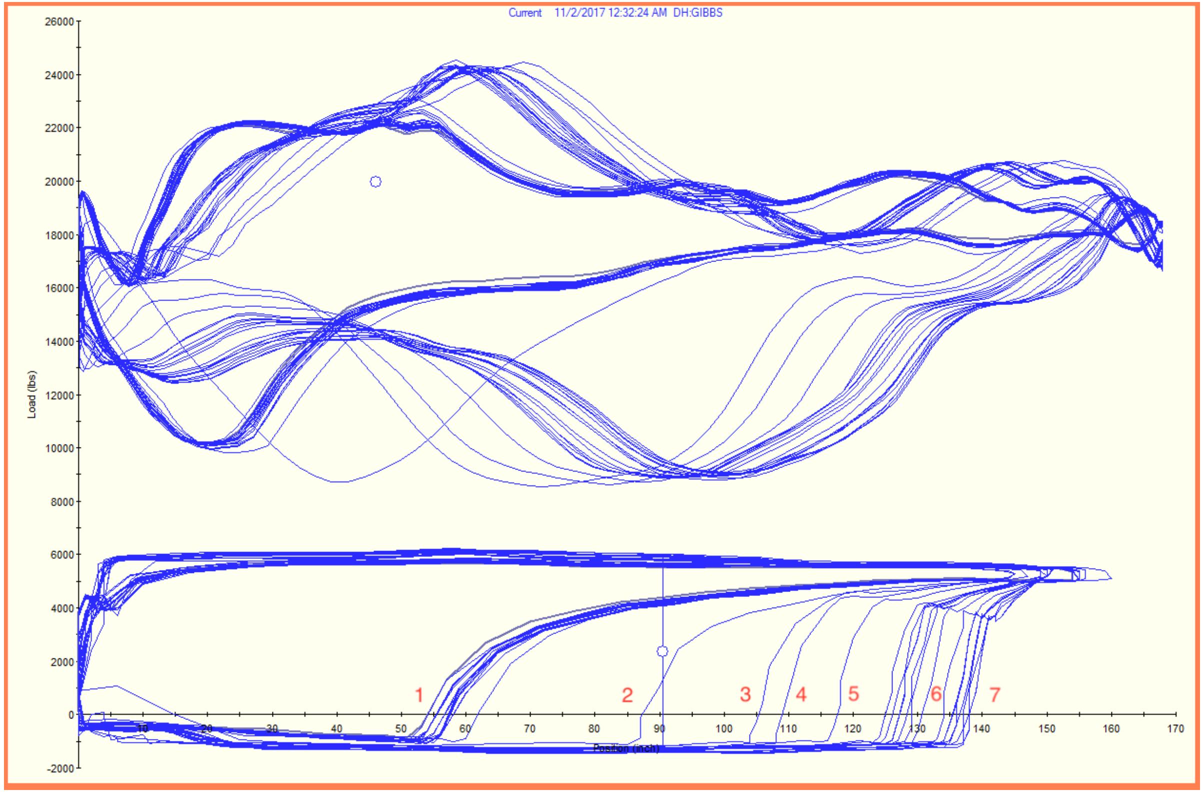

**Figure 4 – Well R dynamometer card**

# Horizontal Well Control

- Well E
  - Horizontal well controlled via POC prior to December 2017
  - Daily runtime varied due to gas interference violating pump-off setpoint



# Well E Slugging Behavior

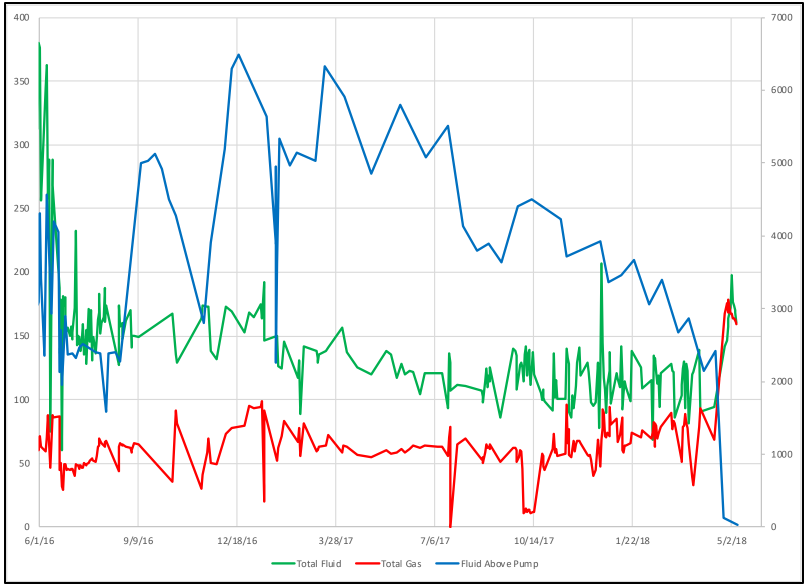


# Well E Slugging Behavior

- Idle time is difficult to configure due to varying slug durations
- Recommended to set shorter than normal idle times if using POCs on horizontal wells
  - Allows for restart as soon as possible after slug has ended
- If slug has not passed, well immediately goes idle again

| Description | Address | Host | RTU |
|---|---|---|---|
| Last 20 Run tims [mins] 1 | 37505 | | 5 |
| Last 20 Run tims [mins] 2 | 37506 | | 61 |
| Last 20 Run tims [mins] 3 | 37507 | | 6 |
| Last 20 Run tims [mins] 4 | 37508 | | 6 |
| Last 20 Run tims [mins] 5 | 37509 | | 165 |
| Last 20 Run tims [mins] 6 | 37510 | | 6 |
| Last 20 Run tims [mins] 7 | 37511 | | 62 |
| Last 20 Run tims [mins] 8 | 37512 | | 6 |
| Last 20 Run tims [mins] 9 | 37513 | | 5 |
| Last 20 Run tims [mins] 10 | 37514 | | 164 |
| Last 20 Run tims [mins] 11 | 37515 | | 5 |
| Last 20 Run tims [mins] 12 | 37516 | | 6 |
| Last 20 Run tims [mins] 13 | 37517 | | 76 |
| Last 20 Run tims [mins] 14 | 37518 | | 6 |
| Last 20 Run tims [mins] 15 | 37519 | | 6 |
| Last 20 Run tims [mins] 16 | 37520 | | 197 |
| Last 20 Run tims [mins] 17 | 37521 | | 5 |
| Last 20 Run tims [mins] 18 | 37522 | | 5 |
| Last 20 Run tims [mins] 19 | 37523 | | 168 |
| Last 20 Run tims [mins] 20 | 37524 | | 6 |

# Well E Production




- After VSD installation in December 2017, fluid level began to gradually decrease
- After FAP (blue) dropped below 2,000 ft, total fluid production (green) increased from 100-120 bbl/D to over 160 bbl/D

# Well P VSD Installation

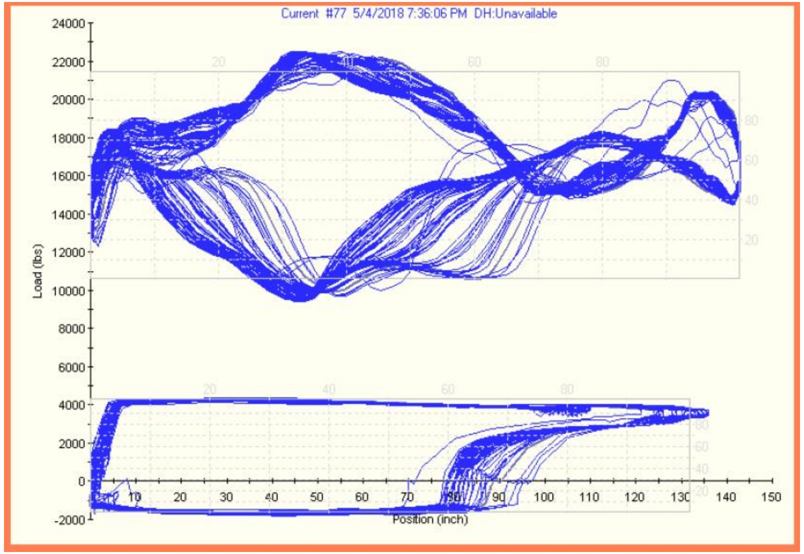



Figure 11 – Well P gas interference at 7 SPM

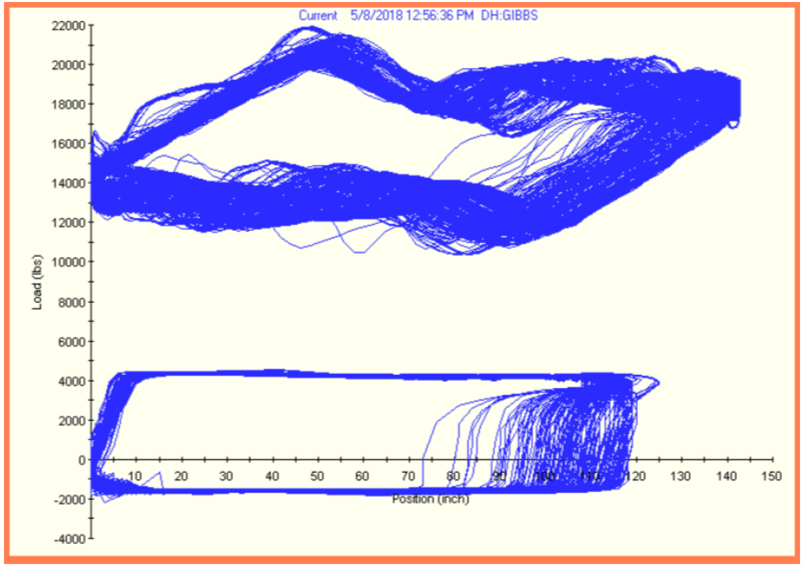
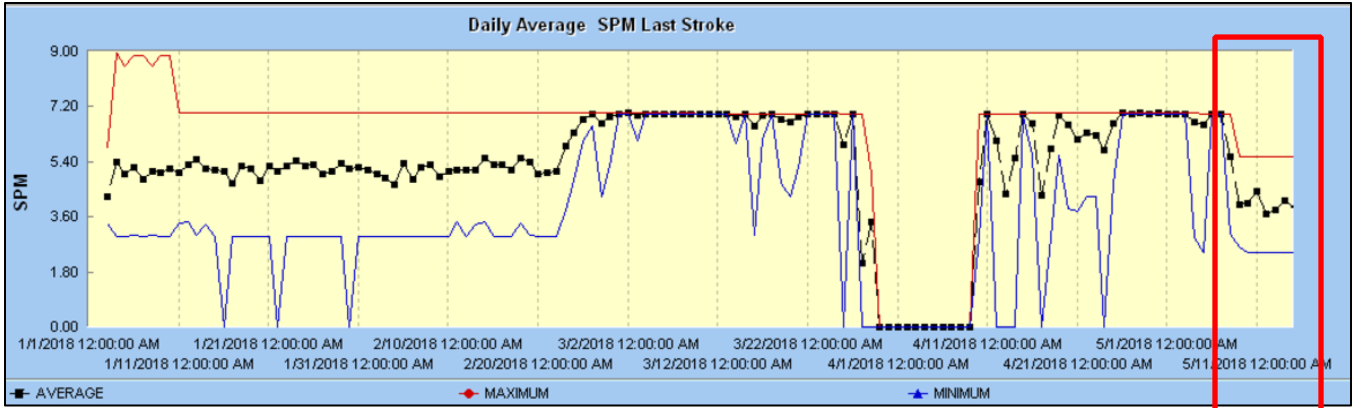


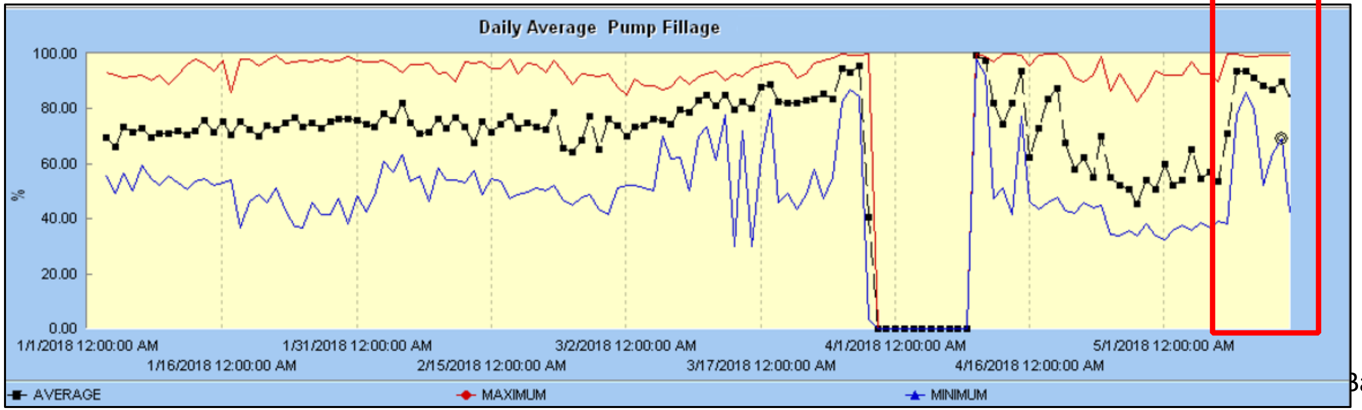

Figure 12 – Well P after reducing maximum speed to 5.6 SPM

# Well P VSD Installation

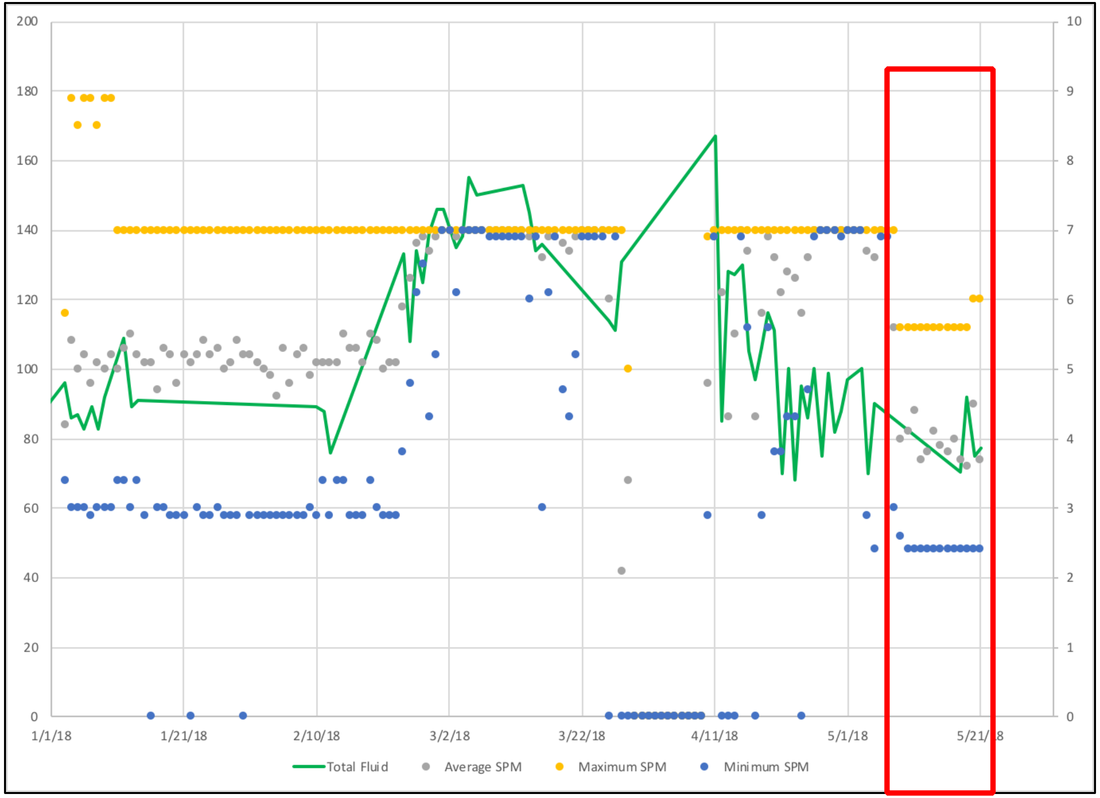
- After reducing maximum speed to 5.6 SPM, gas interference was no longer evident in the cards
- Pump fillage was consistently higher
- 5.6 SPM equates to 3.1 in./sec liquid velocity through the installed separator
    - o This may be caused by the lower water cut of 26%

# Well P Pump Fillage Increases with Decrease in Maximum SPM



# Well P Production



# Reduced Backpressure

- Thirteen wells were selected to reduce backpressure from 200-300 psi to line pressure
  - Rod stress decreased from 0-7.7%
  - Polished rod horsepower decreased from 0-18.8%
  - Pump displacement increased from 0.2-13.7%
  - Production remained constant

# Reduced Backpressure Dynamometer Changes

- Reducing backpressure causes changes in loads that affect the surface dynamometer shape
- This change may violate the POC setpoint if set very conservatively
- This may explain previous field experience that wells “stop pumping” when backpressure is lost
- Controlling from downhole pump fillage may alleviate this issue

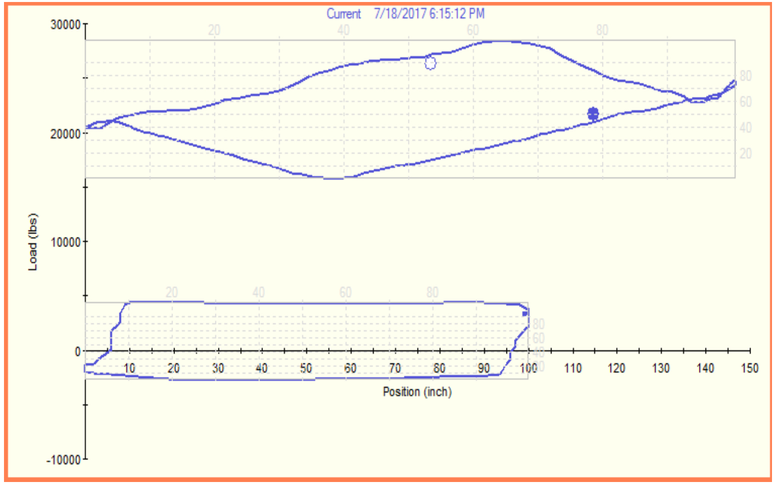



**Figure 17 – Well B with 300 psi backpressure**

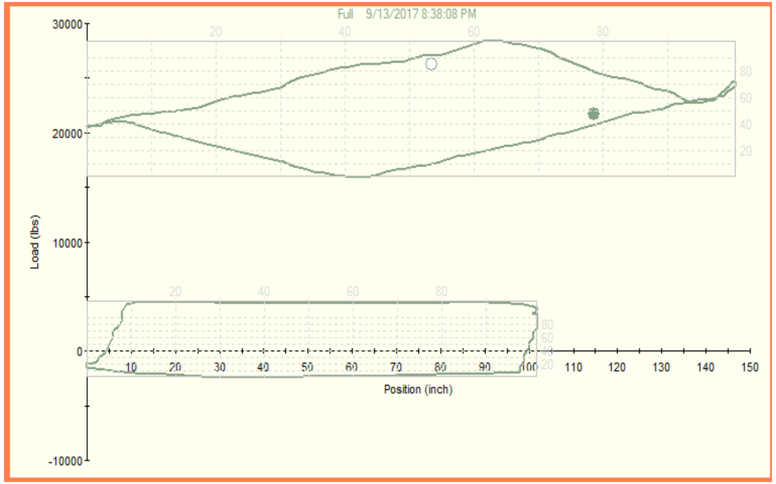



**Figure 18 – Well B after removing backpressure**

# Conclusions

- Handling associated gas produced in unconventional oil wells presents a significant challenge in the design and operation of sucker rod pumping systems
- The assumption of 6-in./sec bubble rise velocity when sizing gas separators is not always accurate
    - More work is needed to quantify the proper velocity to use for varying water cuts and bottomhole pressures
- VSDs can better adjust to the changing conditions caused by slugging wells than POCs
- Increasing backpressure at the surface does not impact gas interference at the pump and has many negative effects

# Acknowledgements


- Thanks to our engineering and operations teams for their assistance through this project
- Thanks to Occidental Petroleum for supporting this project and publication of its results

# Questions?