Mitigate slug flow to increase the maximum rod pumping rate and allow earlier transition to rod pumping

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Production and lifting strategies are characterized by transitions

**Predicament**

- Must address how to implement the lowest cost lifting system as soon as possible that maximizes drawdown reliably
- Top end of rod pumping is below bottom end of natural flow
- Rod pumping is the preferred choice for low per barrel costs

**Slug Mitigation Strategy**

1. Control flowback
2. Maximize natural flow period (lowest OPEX)
3. Eliminate or minimize intermediate artificial lift phases
4. Transition to rod pump as early as possible to minimize OPEX
5. Maximize pump reliability and drawdown
Challenges producing deep high-rate horizontal wells

1. Transitions can reduce a well’s NPV:

   • They are costly, often requiring multiple workovers to go from frac flow back to natural flow, natural flow to artificial lifting, and between intermediate artificial lift phases

   • They can reduce proppant / frac conductivity

       • Interruptions to production can cause large BHP pressure fluctuations and periods of excessively high production rates (proppant flowback events, loss of proppant conductivity, solids bridges in the horizontal)

       • Excessive load fluids in formation and types of load fluids can damage the formation
Case Study #1: Controlling flowback

- Maximum pressure to maintain stability of proppant pack
- Maximum flow rate (velocity for sand transport)
- In example, rates were above the level of proppant pack stability
- Evidence that periodic high rates from interruptions and slug flows can reduce proppant conductivity

Case Study #1: Controlling flowback

- Stay within the stable operating envelope from day one to maintain maximum proppant conductivity ultimately enhancing production and EUR

- Evidence that avoiding interruptions (transitions) and mitigating slug flows can sustain proppant conductivity

Challenges producing deep high-rate horizontal wells

2. Slug flows from the horizontal during production can reduce a well’s NPV:

• Excessive pump gas interference, high fluid levels and reduced pump reliability / efficiency

• Excessive BHP fluctuations which subsequently can reduce frac conductivity

• Encourage solids production, transports solids along horizontal wellbore and can damage the pump

• Cause cyclic periods of annular gas flows that exceed the liquid critical lifting rate (facility overloads, very large BHP fluctuations)

• Limits drawdown and reserves (placing a pump shallower above bend/curve section to control reliability risks or high pump jack loads or leads sub-optimal application of gas lifting)
Severe slug flow conditions occur around bend / curve compounds slugging in Hz

Source: https://youtu.be/DTl10BeLHv0
Challenges producing deep high-rate horizontal wells

3. Pumping from deeper depth risks:

- Complicated production parameters for right sizing equipment
  - High initial production rates followed by high decline rates
  - High gas to liquid ratio production (risk of pump gas interference, risk of foam generation by downhole equipment)

- Drilling minimizes costs by using smaller casings
  - Risk of annular critical liquid lifting rate issues
  - Reliability risks with smaller pumps and equipment

- Excessive rod / pump loadings and power requirements

- Greater rod loadings accelerate rod and tubing wear

- Frac hit risks impose planned and unplanned costly workovers
Approach to resolving challenges

Apply a slug flow mitigation downhole system to industry’s largest pump jacks to demonstrate reliable and low OPEX production performance at 500 – 600 bbls/day below 6,000 foot depths

• achieve high pump efficiency at reduced peak polish rod loading
• avoid downhole foam generation
• place pump at shallower depth and in vertical section
• benefit an earlier transition to lower OPEX rod pumping

Extend natural flow as long a possible, while closing the gap for an intermediate artificial lift requirement

• reduce size of intermediate lift equipment
• simplify transition to rod pumping and transition as early as possible
Industry’s largest pump jack capabilities

Rotaflex® Long-Stroke Pumping Unit

<table>
<thead>
<tr>
<th>Depth</th>
<th>Rotaflex 1100 Without Drive</th>
<th>Rotaflex 1100 With Drive</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pump Size</td>
<td>SPM</td>
</tr>
<tr>
<td>2,000 ft (609 m)</td>
<td>5.75</td>
<td>4.30</td>
</tr>
<tr>
<td>3,000 ft (914 m)</td>
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<tr>
<td>12,000 ft (3,657 m)</td>
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Theoretical 500 - 800 bbl/d @ 100% efficiency at 10,000 feet


- With consistent high pump fillage, theoretically 500 - 600 bbl/day is possible
- The shallower the PSN the greater the rate capacity

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Slug flow is the root cause of poor artificial lift performance
Case Study #2: Slug flow mitigation improves separation and pump fillage

- 23 neighboring wells and 140 readings over seven months
- Slug flow mitigation improves downhole separation, downhole system fillage is higher and more consistent
- Stable fluid level allows for effective pump jack balancing

Wolfcamp, Permian Basin

Case Study #3: Slug flow mitigation demonstrates consistent pump fillage

- Slug flow mitigation solves erratic pump fillage and gas interference
- Consistent pump fillage > 90%
- Considerable reduction in rod stress and erratic rod stress
- Increase in pump efficiency and a shallower pump placement reduces energy consumption up to 40%

Niobrara, DJ Basin

Case Study #4: Slug flow mitigation

The Downhole System:

- Considerably reduce slug severity around bend to manageable levels for pump (consistent high pump fillage achieved)
- Reduced Taylor bubble and liquid slug lengths (pressure cycling and solids transport) along horizontal
- Modelled in Pipe Fractional Flow to determine manageable Taylor bubble lengths

Downhole System for slug flow mitigation

Conventional Artificial Lift

HEAL Vortex Separator

Sized Regulating String (SRS) - variable ID

Large solids sump

HEAL Seal

Separated gas

Separated oil + water + solids

Fluids turn corner to bottom of shroud

Solids to sump
Risk-Based Design

Resolving deep high-rate high decline production challenges required a risk-based design approach on three mutually exclusive phases:

1. Installation phase
   • Trouble-free and low cost installation

2. Production phase
   • Deal with root issue – mitigate slug flows
   • Design for long-term mechanical integrity under cyclic fatigue load conditions
   • Minimize and simplify number of transitions
   • Simple and low cost frac hit protection

3. Retrieval and/or Maintenance phase
   • Low risk of retrieval in solids, scale and corrosive laden environments
Trade-offs between installation and retrieval phase risk has led to the development of specialized components:

- No rotation, axial and linear set / release downhole tools (packers and on/offs)
- Design for operation in solids / scale / corrosive environments
- One trip single completion systems
Installation and retrieval risk management

Safe Disconnect Tool Design Attributes:

• Inverted on/off tool with slick joint on end of SRS (allows for lower risk retrieval in a solids laden environment)

• Overshot connected to packer

• Auto-J for no rotation, axial connecting and disconnecting
Installation and retrieval risk management
Incorporated slickline componentry into the Downhole System:

- allows for simple and cost-effective transitions from frac flowback, to natural flow and into the artificial lifting phase
- allows for simple and cost effective transitions between gas lift, plunger lift and rod pumping.
- benefit of low cost frac hit protection from offset wells

Slickline System: Extend natural flow and transition to rod pumping

**Flowback and Natural Flow**
- Post frac Slickline System is installed
- Flow through mandrel installed in slickline separator
- All produced fluids and entrained solids are produced to surface
- SRS is sized to mitigate slug flows
- Extends natural flow period as SRS lifts fluids around bend and delays the onset of liquid loading

**Rod Pump**
- Well is no longer capable of natural flow and can be cost effectively transitioned to rod pumping without pulling tubing
- Pull flow through mandrel and install separator mandrel
- Run pump and rods

Insert Pump

HEAL Slickline Separator c/w flow through mandrel

HEAL Slickline Separator c/w separator mandrel

Formation Fluids (Oil, Water, Gas)
Separated Gas
Oil / Water
Separated Solids

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Slickline System for offset well frac hit protection

- Well is on production with rod pump and Downhole System for slug flow mitigation
- Slickline separator mandrel in place
- Offset well to be fracced, presenting a risk of a frac hit

Rod Pump

- Rods/pump are pulled from well
- Slickline unit pulls Separator Mandrel and installs blanking plug in slickline separator
- With deep well barrier, frac hit risks and consequences are mitigated
- Post offset well frac, procedure is reversed and well is placed back on production

Frac Hit Protection

- Insert Pump
- HEAL Slickline Separator c/w Separator Mandrel
- Formation Fluids (Oil, Water, Gas)
- Separated Gas
- Oil / Water
- Separated Solids
- HEAL Slickline Separator c/w Blanking Plug (w/ optional pressure gauge)

SRS

HEAL SEAL
Case Study #5: high rate deep rod pumping

Gas Lift to long stroke pumpjack @ 8,200 ft:
- Inconsistent production with gas lift
- Consistent production after install
- 86% increase in total fluid rate
- > 85% consistent pump fillage
- Reduced operating costs
1. Mitigating slug flows from the horizontal:
   • increases the maximum rod pumping rate and reliability
   • allows for earlier transition to rod pumping

2. Incorporation of slickline componentry has lowered production phase transition risks and costs
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