Smart Automation of Plunger Lift Systems

Exploring the Benefits of Plunger Automation and Advanced Optimization Technologies

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Smart Automation of Plunger Lift Systems: Topics
★ Introduction
★ Liquid Loading and Plunger Lift
★ Conventional Controls and Methane Losses
★ Plunger Lift Optimization
★ Field Experience
★ Discussion
Liquid Loading
★ Build-up of hydrocarbons (condensate) and water in wellbore which reduces and may halt production.
★ Multi-phase flow has three distinct forms:
  ★ Bubble
  ★ Slug
  ★ Annular Mist
★ Deliquification methods can vary based on well characteristics and preferences.

Plunger Lift
★ Intermittent artificial lift method that uses the energy of the reservoir to bring the liquids to the surface.
★ Cyclic process with the well alternately flowing and shut-in. Each cycle removes built-up liquids from the formation.
★ Due to a wide variety of formation characteristics and wellbore irregularities, each well will have distinct behaviors and “personality”.
Conventional Plunger Control

- Manual adjustments to cycle parameters (shut-in time, flow time, etc.) are problematic:
  - Adjustments are not performed regularly
  - Do not account for changing down-hole (liquid production, pressure) or collection conditions (line pressure, separation equipment)

- Fixed cycle times may not match well performance:
  - Cycle too frequently
    - High plunger velocity
    - Excessive plunger wear
  - Not frequently enough
    - Liquid loading becomes excessive
    - Plunger unable to reach surface

Methane Losses

- Liquid loaded plunger wells that will no longer produce gas must be blown down to the atmosphere.

- Onshore well venting and flaring releases 9 Bcf/year of methane.
Plunger Lift Optimization

★ Using well-known algorithms and real-time monitoring of well conditions, cycle performance can be evaluated each cycle:
  ★ Plunger velocity
  ★ Liquid loading (casing/tubing pressure)

★ Adjustments to cycle parameters can be made based on evaluated performance:
  ★ After flow duration
  ★ Shut-in time duration

Evaluating Performance

★ Plunger velocity:
  ★ Each plunger type will have specific operating velocity for which it was designed to perform best.
  ★ The optimization routine will calculate velocity based on arrival time and tubing length.
  ★ An arrival will be designated as Fast, Normal, Slow etc. based on configurable time “windows”.

★ Liquid loading and load ratio:
  ★ Liquid loading of the well is determined by the difference of the casing pressure and the tubing pressure.
  ★ Well energy is estimated by taking the difference of the casing pressure and the line pressure.
  ★ The ratio of the well’s liquid load and the energy is the load ratio.
Parameter Adjustment

★ Shut-in duration:
★ The load ratio (LR) is calculated from well conditions.
★ After enough time is elapsed for the plunger to reach the bottom, the cycle compares the load ratio to a setpoint.
★ When the LR has dropped below the setpoint, the well is brought online.

★ After flow duration:
★ The well’s critical rate (rate at which liquid can remain entrained) is calculated from well conditions.
★ The “drop rate” is calculated as a percentage of the critical rate.
★ The percentage is adjusted each cycle based on whether the previous arrival was Fast or Slow.

Optimization Advantages

★ Plunger cycles adapt to changing conditions:
★ Line pressure swings
★ Liquid surges from within the formation
★ Plunger mechanical wear
★ Greatly reduced venting
★ Increased uplift volumes:
★ Cycles adapt toward optimum frequency
★ Well life is extended from consistent deliquification
★ Plunger wear reduced
★ Manpower requirements reduced
Economics of Advantages

- Well production will generally increase
  - Optimized plunger cycles can increase well production by 10 to 20%
  - The decrease in needed venting can provide an additional production increase of 1 to 2%
  - Manpower requirements reduced by half

- Simple payback calculation:
  \[(50,000 \text{ Mcf/yr}) \times (10\% \text{ increased production}) \times ($4/\text{Mcf})\]
  \[(50,000 \text{ Mcf/yr}) \times (1\% \text{ vent savings}) \times ($4/\text{Mcf})\]
  \[(500 \text{ personnel hrs/yr}) \times (0.5) \times ($30/hr)\]
  \($12,000 \text{ installed cost}\)

$17,500 savings in first year (5 month simple payback)

Field Experience at BP

- Installation of optimization in 2000
  - Plunger optimization installed on ~2,200 wells
  - Most sites required installation of logic controllers or RTU’s (Remote Terminal Unit)
  - Central hosting system also installed to collect and monitor field data from RTU

- Venting was reduced by 50% from 2000 - 2004
Field Experience at BP

Discussion

★ Limitations of optimization
★ Other applications
  ★ Different plunger types
  ★ Intermitters
★ Expertise requirements and learning curve