Understanding and Improving Gas-Lift Compressor Operations

Bill Elmer  Encline Technologies
Larry Harms  Harmsway Optimization
Where does your expertise lie?

- OXY Chief Production Engineer Shauna Noonan at 2017 Gas-Lift Workshop:
  - Historic Life Cycle of Permian was ESP then Sucker Rod Pump
  - Both methods had high failure costs and downtime
  - Tested other artificial lift forms, including gas-lift
  - Gas-lift gave excellent results: better runtime, tolerant of gas slugging, better production, and not impacted by deviation
Where does your expertise lie?

- Shauna Noonan at 2017 Gas-Lift Workshop:
  - Local organization skilled with ESP’s and rod pumps
  - Local organization resistant to gas-lift
  - Sourced gas-lift expertise elsewhere in company
  - Now all new drills to be gas-lifted
  - Implications are closer wellheads and more wells per pad
Where does your expertise lie?

- Peter Oyewole in SPE 181233 “Artificial Lift Selection Strategy to Maximize Unconventional…”
  - Gas-lift fastest growing lift system in Delaware Basin
    - Lower Operating Expenses
    - Better understanding of formation / fluid behavior
  - Initial reluctance to gas-lift driven by lack of experience

Is it time to put our preferences for rod pumping and ESP’s behind us, and own gas-lift?
Thrown in the deep end?

- While not preferred, many of us learned about gas-lift / compressors this way.

- Since the compressor is the heartbeat of the gas-lift system, understanding its operation is paramount.

- Simply a matter of building experience.
Changing Discharge Pressure Needs

- Conventionally valved gas-lift designs usually require pressures between 1000 to 1200 psi
  - Higher pressure = Less gas-lift valves
  - EagleFord Example: 1000 psi = 10 valves
    - 1200 psi = 6 valves, 1500 psi = 4 valves
- In days of waterfloods and gas reinjection, bottom hole pressure kept above this level, requiring valves forever

Feb. 4 - 7, 2018 2018 Artificial Lift Strategies for Unconventional Wells Workshop Oklahoma City, OK
Changing Discharge Pressure Needs

- NOT the system used today
  - Individual leases in competitive situations drive goal for low flowing BHP
  - No pressure maintenance projects
- Once injection reaches the bottom orifice or flows around end of tubing:
  - BHP and therefore injection pressure will drop as liquid production drops
Changing Discharge Pressure Needs

- Gas-Lift combined with plunger lift has demonstrated ability to achieve producing BHP's near 300 psi, using less lift gas
  - Eric Perner / Stan Lusk at 2015 Gas Well Deliquification Workshop – ability to handle rates of 200-250 BFPD
  - Dawn Lima / Matt Young at 2017 Gas Well Deliquification Workshop – achieved ~200 psi reservoir pressure by adding Plunger to Gas-lifted wells, a drop of 120 psi on wells making about 50 BFPD
Changing Discharge Pressure Needs

- When SIBHP falls below the available injection system pressure, gas-lift valves are no longer needed.
- If a high pressure compressor available, gas-lift valves never required (Harms).

Gas-lift valves for Unconventional Wells may only be needed in the short term, if at all.
Changing Discharge Pressure Needs

• Can compression equipment deliver the injection pressure needs over the well’s life?

• Is it practical to have both a high and medium pressure gas-lift system? (Has been done offshore)

• Does wellhead compression better meet the pressure needs of an individual well?
Gas Sales Versus Gas-Lift

- **Gas Sales:** Historically designed for lean gas, with a glycol dehy downstream
  - Gas cooler designed to support dehy
    - Keep discharge gas below 100 F
    - Minor hydrocarbon condensation (as little C3+ present in gas)
  - Normally blown down when restarting
  - Bypasses of little use
  - Suction and Discharge Pressures steady
Gas Sales Versus Gas-Lift

- Gas-Lift: Warm gas desired
  - Gas cooler (to support dehy) is too big
  - Major hydrocarbon condensation problems
    - Creates VRU problem for downstream equipment
    - Hydrates in discharge and scrubber dump lines
  - Skid blowdown can mist location with drip
  - Bypasses to allow full flow, avoid blowdown
  - Suction and Discharge Pressures not steady
Eagle Ford Gas Analysis

- 10% by volume are Propane and heavier
- 3.04 gallons per MCF, 72 BBL per MMCF
- Cooling determines how much condenses

<table>
<thead>
<tr>
<th>Index</th>
<th>Name</th>
<th>Normalized [mole %]</th>
<th>Wt%</th>
<th>GPM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>C6+</td>
<td>0.7595</td>
<td>3.1693</td>
<td>0.33</td>
</tr>
<tr>
<td>2</td>
<td>Nitrogen</td>
<td>0.2635</td>
<td>0.3351</td>
<td>0.00</td>
</tr>
<tr>
<td>3</td>
<td>Methane</td>
<td>75.6365</td>
<td>55.0862</td>
<td>0.00</td>
</tr>
<tr>
<td>4</td>
<td>Carbon Dioxide</td>
<td>1.6681</td>
<td>3.3327</td>
<td>0.00</td>
</tr>
<tr>
<td>5</td>
<td>Ethane</td>
<td>12.4838</td>
<td>17.0411</td>
<td>3.32</td>
</tr>
<tr>
<td>6</td>
<td>Propane</td>
<td>5.8949</td>
<td>11.8008</td>
<td>1.62</td>
</tr>
<tr>
<td>7</td>
<td>n-Butane</td>
<td>0.7408</td>
<td>1.9547</td>
<td>0.24</td>
</tr>
<tr>
<td>8</td>
<td>n-Butane</td>
<td>1.6990</td>
<td>4.4831</td>
<td>0.53</td>
</tr>
<tr>
<td>9</td>
<td>n-Pentane</td>
<td>0.4078</td>
<td>1.3359</td>
<td>0.15</td>
</tr>
<tr>
<td>10</td>
<td>n-Pentane</td>
<td>0.4461</td>
<td>1.4510</td>
<td>0.16</td>
</tr>
</tbody>
</table>

Total: 100.0000 100.0000 6.36
Prevent Hydrocarbon Condensation

- Causes scrubber dump lines to freeze
- Causes hydrates in discharge cooler and piping
Prevent by Keeping Gas above 125°F

- Phase diagram shows this will keep gas in 100% vapor phase at any pressure
- Gas cooling systems need modification
  - Individual louvers on each cooling stage
  - Total bypass or 3 way bypass around aftercooler (for positive shutoff)
  - Warm air recirculation system
  - Shell and tube heat exchangers
  - VFD driven cooling fan motor
Alternative to Warm Gas?

- Methanol Injection
  - May work against corrosion inhibitor proper film development
  - Methanol normally contains dissolved oxygen, returns as iron oxide
  - Expensive and dangerous (burns without visible flame)

Quoting NACE 07663 (Park 2007):

- “High quantities of methanol may reduce the success of a corrosion inhibitor program. Although corrosion mitigation is used in conjunction with methanol injection, as an industry-wide and commonly accepted practice, there is very little literature on the subject.”
Centralized Versus Wellhead

- **Centralized Compression – Pro’s**
  - Cost per unit of injection gas lowest
  - Larger equipment often more reliable
  - More wells per pad, the better

- **Con’s**
  - Sizing: Difficult to forecast volume needs
  - Gas reaches earth temperature after 1000 feet
  - Fuel gas may require processing
  - All wells receive pressure of highest well
Centralized Versus Wellhead

Wellhead Compression – Pro’s
- Hot, rich gas can prevent paraffin issues
- Sizing: Simple
- Can be electric driven to minimize downtime
- Gas compressed to casing pressure, no higher
- Methanol can be eliminated via temp control

Con’s: Many more compressors to install, permit, and maintain (cost)
Automation of Compressor Rate and Well Injection Rates

- Equipped with packer and orifice with 330 MCFPD steady injection rate

24 Hour Gross Gas Rate - MCFPD
Automation of Compressor Rate and Well Injection Rates

• A case for Aggressive Injection Rate Control?
  • Well geometry responsible for slugging liquid
  • Gas accumulates in high spots of lateral, expelling liquid in gassy slugs
  • Liquid followed by high gas rates since well in a blowdown state
  • Injection rate of 330 MCFPD prolongs blowdown state, and elevates frictional losses

• Did the packer and orifice provide value?
Automation of Compressor Rate and Well Injection Rates

• Excessive injection serves to increase BHP and reduce production rate
  • Should injection rate be reduced to zero during blowdown?
  • Should injection rate be increased to 500 MCFPD or more when production rate falls below “critical”?
• Industry needs to work on tuning injection depending on what is happening downhole
Automation of Compressor Rate and Well Injection Rates

- Gas Compressors must provide what the well needs, not the other way around
  - The asset is the well. Don’t let tail wag the dog
  - Compressor can be equipped with 100% bypass even under load using an unpopular line heater

- High tech engines allow limited turndown
  - Won’t meet emission tests when unloaded
  - Don’t put a 5 MMCFPD machine on a 2 MMCFPD load thinking more wells will come
Automation of Compressor Rate and Well Injection Rates

- Capacity Options Easily Automated
  - Speed Decrease – 20%
  - Suction Pressure Decrease – 20%
  - Risk auxiliary systems not keeping up
    - Engine jacket water pump
    - Turbocharger
- Bypass with line heater
  - Automated choke
Compressor Safety / Emissions

- Blowdown can be minimized by bleeding to gas sales line on shutdown
- Alternative method to contain all pressure on skid by using higher pressure components and full flow bypass
  - Minimizes hearing loss, drip raining on location on cold days, risk of explosion due to heavier components of rich gas
  - Good to sell it instead of releasing
Artificial Lift “Life Cycle”

- 2017 Gas-Lift Workshop Keynote Address
  - Historic Life Cycle: Flowing, ESP, Rod Pump
  - New Life Cycle: Gas-Lift
    - Annular
    - Conventional
    - Intermittent
    - Gas Assisted Plunger Lift
    - Chamber Lift
High Pressure Gas-Lift: Is Industry Missing a Potentially Huge Application to Horizontal Wells?

- Presented at 2017 SPE ATCE in San Antonio
- SPE 187443 by Larry Harms and Bill Elmer

Single Point Gas-Lift can be the single and only form of artificial lift needed

- Downhole requirements: one string of tubing for life of well
Annular Single Point Gas-Lift
Shauna Noonan at 2017 ALRDC Gas-Lift Workshop: “Certain areas don’t have sufficient source of lift gas”

This is a common misperception

Think of Gas-lift like your air conditioner

- Pump the same Freon around again and again
- Works fine unless there is a leak
- Just need to initially “fill” the gas-lift system
How much lift gas is needed to fill system (to 1000 psig)?

- 2-3/8” x 4-1/2” annulus: 3.9 MSCF per 1000 feet
- 2-3/8” x 5-1/2” annulus: 7.1 MSCF per 1000 feet
- 2-7/8” x 5-1/2” annulus: 6.1 MSCF per 1000 feet

10,000 foot well with 2-3/8” x 5-1/2” annulus holds 71 MSCF at 1000 psi

- Add generous 9 MSCF for surface piping
- Total requirement is 80 MSCF
- For 400 MSCFPD injection rate, gas makes 5 roundtrips per day (5 times per day x 80 MSCF)
Solution to Loss of Lift Gas

- Operating practices can minimize loss of lift gas
- On compressor shutdown, shut-in well to prevent well from blowing down to flare
  - Gas strung up tubing collects below master valve
  - Available for re-injection on start up
- Diligence
  - Make sure level controllers working properly
  - Make sure dump valves are not leaking
  - Compressor rod packing in good condition
    - New packing can leak from 2.5 to 5 MSCFPD
Compressor Tips: Create KPI’s

- Measure compressor outlet volume
  - Compressor should not only run, but perform
- Measure fuel gas use
  - Helps create KPI’s of engine performance
- Using Scada, pull the following data:
  - Temperature in and out of each cooler
  - Pressures in and out of each cylinder
  - Engine RPM, pressure and temp data
  - Count scrubber dump cycles
Rights to this presentation are owned by the company(ies) and/or author(s) listed on the title page. By submitting this presentation to the Artificial Lift Strategies for Unconventional Wells Workshop, they grant to the Workshop, the Artificial Lift Research and Development Council (ALRDC), and the Southwestern Petroleum Short Course (SWPSC), rights to:

- Display the presentation at the Workshop.
- Place it on the www.alrdc.com web site, with access to the site to be as directed by the Workshop Steering Committee.
- Place it on a CD for distribution and/or sale as directed by the Workshop Steering Committee.

Other use of this presentation is prohibited without the expressed written permission of the author(s). The owner company(ies) and/or author(s) may publish this material in other journals or magazines if they refer to the Artificial Lift Strategies for Unconventional Wells Workshop where it was first presented.
The following disclaimer shall be included as the last page of a Technical Presentation or Continuing Education Course. A similar disclaimer is included on the front page of the Artificial Lift Strategies for Unconventional Wells Web Site.

The Artificial Lift Research and Development Council and its officers and trustees, and the Artificial Lift Strategies for Unconventional Wells Steering Committee members, and their supporting organizations and companies (here-in-after referred to as the Sponsoring Organizations), and the author(s) of this Technical Presentation or Continuing Education Training Course and their company(ies), provide this presentation and/or training material at the Artificial Lift Strategies for Unconventional Wells Workshop "as is" without any warranty of any kind, express or implied, as to the accuracy of the information or the products or services referred to by any presenter (in so far as such warranties may be excluded under any relevant law) and these members and their companies will not be liable for unlawful actions and any losses or damage that may result from use of any presentation as a consequence of any inaccuracies in, or any omission from, the information which therein may be contained.

The views, opinions, and conclusions expressed in these presentations and/or training materials are those of the author and not necessarily those of the Sponsoring Organizations. The author is solely responsible for the content of the materials.

The Sponsoring Organizations cannot and do not warrant the accuracy of these documents beyond the source documents, although we do make every attempt to work from authoritative sources. The Sponsoring Organizations provide these presentations and/or training materials as a service. The Sponsoring Organizations make no representations or warranties, express or implied, with respect to the presentations and/or training materials, or any part thereof, including any warranties of title, non-infringement of copyright or patent rights of others, merchantability, or fitness or suitability for any purpose.