DESIGN OF GAS HANDLING FACILITIES FOR SHALE OIL PRODUCTION

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Mike Conder and April Schroer
Overview

› Trends in Gas Handling from Shale Oil Production
› Designing with PVT Fluid Analyses
› Simulating Gas Handling at Oil Production Facilities
› Using GOR Data
› Modeling Different Oils
› Lift Gas Design & Sources
› VRT Design & VRT/VRU System Value
› Practical Tips for Facility Design
Trends in Gas Handling from Shale Oil Production

- Single well pads transition to multi-well pad production
  - Low volume vertical wells to high volume horizontal wells
  - Change in Size & Complexity
  - Increase air emission requirements
    - Pushing threshold limits – esp. VOCs

- Oil Price Boom to Slump Mentality
  - Boom
    - Projects schedule driven
    - Projects not necessary based on long term economics
    - Little published on “more” complex designs and operation
  - Slump
    - Projects transitioning to “Cost” driven
    - “Critical” economic project drivers

- Use “slump time” to improve facility designs
Designs for Shale Oil/Gas Handling – “Traditional”

“Traditional” Well Pad typical flow sheet
Designs for Shale Oil/Gas Handling “4 Well Multi”

4 – Well Multi-Well Pad Flow Sheet
Designing with PVT Fluid Analyses

- **PVT** (Pressure-Volume-Temperature) fluid properties analysis
  - Mainly used for planning field exploitation by reservoir engineers
  - However, facilities engineers can use this information for equipment design
    - Predict gas handling requirements of the well and/or field

- **PVT samples are typically taken at surface separator**
  - Gas/Oil/Water samples taken & then recombined in the lab
  - GC results are carbon number (CN or “alkane – straight chain”) analysis
  - Typical range from C1 (methane) to C36 with inerts

- **CN can be used in a process simulator for equipment sizing**

- **Our work is based on VMG Sim “PIONA” (Paraffin's, Iso-paraffins, Olefins, Naphthenes and Aromatics) new oil characterization**
  - Gives improved liquid property results
Simulating Gas Handling at Oil Production Facilities

- Oil characterization by PIONA vs straight chain CN data
- Little difference in gas production & analysis between two cases
- Credible difference in oil properties
- Need best oil properties for stabilization designs & meeting transport specs
- Off gas flow from a stabilizer will impact facility & gas/handling design

Table 1

<table>
<thead>
<tr>
<th>Process Simulation Comparisons</th>
<th>CN (Alkane) Simulation</th>
<th>PIONA Simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High Press Separator</td>
<td>Low Press Separator</td>
</tr>
<tr>
<td>OIL DATA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Make, BPD, @ STD</td>
<td>Oil Production</td>
<td></td>
</tr>
<tr>
<td></td>
<td>609.1</td>
<td>463.1</td>
</tr>
<tr>
<td>API Grav @ STD</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>47.39</td>
<td>57.40</td>
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<tr>
<td>GAS DATA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flow, MSCFD</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>512</strong></td>
<td></td>
</tr>
<tr>
<td>Separator Gas SG</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0.812</td>
<td>1.356</td>
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<tr>
<td>Heating value, BTU/SCF</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>1,350.0f</td>
<td>2,125.0</td>
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<tr>
<td>Total Heating value, BTU/SCF</td>
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<td></td>
</tr>
<tr>
<td></td>
<td><strong>1,431.1</strong></td>
<td></td>
</tr>
<tr>
<td>Well Gas/Oil Ratio (GOR)</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>1,230.7</td>
<td></td>
</tr>
</tbody>
</table>
Using GOR Data

- Reservoir engineers can provide gas-oil ratio (GOR) and type curve (time vs. production)
  - Useful design tool for facilities engineer BUT “use with caution”
  - Normally developed from similar wells in the area (analogue wells)

- GOR data can be misleading
  - GOR usually calculated from actual production data
  - Rarely adjusted for vapor recovery volumes
    - Measured separator oil density lower than final produced oil density
    - Make sure know how GOR is calculated
Using GOR Data (continued)

- Design impacts
  - Well operating conditions strongly influence GOR calculations
  - Differences can range ± 25-50%
  - These differences can impact the equipment design (stabilization)

### Table 2

<table>
<thead>
<tr>
<th>Calculated GOR Values</th>
<th>Alkane (CN) Simulation</th>
<th>PIONA Simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High Press Separator</td>
<td>Low Press Separator</td>
</tr>
<tr>
<td><strong>OIL DATA</strong></td>
<td>Oil Production</td>
<td>Oil Production</td>
</tr>
<tr>
<td>Oil Make, BPD, @ T.P.</td>
<td>617.7</td>
<td>477.0</td>
</tr>
<tr>
<td>Oil Make, BPD, @ STD</td>
<td>609.1</td>
<td>454.8</td>
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<tr>
<td><strong>GAS DATA</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flow, MSCFD</td>
<td>512</td>
<td>11.6</td>
</tr>
<tr>
<td>GOR @ T.P.</td>
<td>841</td>
<td>1,184</td>
</tr>
<tr>
<td>GOR @ STD</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Differences: 46% and 47%**
Modeling Different Oils – Unit Based

- 3 typical oils (lt, med, hvy) modeled using PVT @ same operating conditions
- PVT reported API Gravities: Oil A: 61.3; Oil B: 49.6; Oil C: 35.8
- Oil B was used in the previous calculations

<table>
<thead>
<tr>
<th>Table 3</th>
<th>Process Simulation for Different Oils</th>
<th>Oil Production</th>
<th>Gas Production, MSCFD</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual BPD</td>
<td>Standard BPD</td>
<td>API Grav.</td>
</tr>
<tr>
<td>Oil A</td>
<td>470.1</td>
<td>458.9</td>
<td>63.29</td>
</tr>
<tr>
<td>Oil B</td>
<td>467.9</td>
<td>458.9</td>
<td>41.53</td>
</tr>
<tr>
<td>Oil C</td>
<td>467.2</td>
<td>458.9</td>
<td>41.26</td>
</tr>
</tbody>
</table>

1193% 17%
Modeling Different Oils – (continued)

- HPS production ranges +/- 1200%
- Total LPS & VRT flash gas production only ranges +/- 25%
- LPS/flash gas handling equipment sizing strongly dependent on total oil production
  - Less dependent on GOR
- Simplifies design of gas handling facilities
  - Equipment size based on oil production rates
- The flash gas historically burned
  - State regulations require capturing flash gas for VOC control
  - Recent North Dakota regulations now require capturing most flash gas volumes
Modeling Different Oils – (continued)

- Value of LPS & VRT flash gas not significant for single well facilities, but very significant for multi-well pads
  - 3-6% of total produced gas volume
  - 10-14% of total gas revenue of the well
  - Adds ±$1/bbl. of the oil to the total wells revenue (Q1 Rocky Mtn. prices)

<table>
<thead>
<tr>
<th>Table 4</th>
<th>Gas Production</th>
<th>NGL Recovered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Btu Quantities &amp; $/BBL Values – flash gas 75 psig basis</td>
<td>HPS Gas, MMBTU/D</td>
<td>LP Flash MMBTU/D</td>
</tr>
<tr>
<td>Case 1 - Light Oil</td>
<td>5,721.4</td>
<td>12.7</td>
</tr>
<tr>
<td>Case 2 – Med. Oil</td>
<td>717.3</td>
<td>15.3</td>
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<tr>
<td>Case 3 - Heavy Oil</td>
<td>36.5</td>
<td>1.2</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total Value, $/day</th>
<th>Percent of Total Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1 - Light Oil</td>
<td>37,232</td>
</tr>
<tr>
<td>Case 2 – Med.Oil</td>
<td>3,635</td>
</tr>
<tr>
<td>Case 3 - Heavy Oil</td>
<td>2,629</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total Value, $/BBL Oil Produced</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1 - Light Oil</td>
</tr>
<tr>
<td>Case 2 – Med.Oil</td>
</tr>
<tr>
<td>Case 3 - Heavy Oil</td>
</tr>
</tbody>
</table>
HPS operating pressure affects LPS & VRT flash gas volumes

- Volume and total BTU production increases with HPS pressure
  - 75 psig HPS pressure: flash gas 5% of total flow and 8% BTU value
  - 250 psig HPS pressure: flash gas 16% of total flow and 25% BTU value
Lift Gas Design

- Most shale oil wells need artificial lift to produce the wells

- Gas lift is a common method of artificial lift
  - High pressure gas stream is injected into well bottom
  - Assists in driving produced water/oil to the surface

- Single Well Site lift gas compression
  - Plus: uses HPS gas compressed by pad compressors
  - Plus: easy installation; minimal facilities investment
  - Minus: requires many temporary units, one on each site
  - Minus: high $/hp for small units
  - Minus: no back-up for downtime
Lift Gas Design (continued)

- Centralized lift gas compression
  - Plus: permanent gas lift compression facilities
  - Plus: lower $/HP
  - Plus: back-up for downtime
  - Plus: simple to add new wells; extend pipe
  - Minus: requires installation of gas lift lines & larger gathering systems
  - Minus: potential liquid drop problems in pipe and at well pads

- Dew point units can be installed to prevent liquid problems
  - Removing gas liquids increases net gas production from wells
    - Dry lift gas strips light ends from the oil
    - Helps stabilize the oil
Vapor Recovery Tower (VRT)

- VRT introduced into well pad designs 2012/13
  - Provides a positive suction pressure to VRUs
  - Act as a liquid seal to prevent air ingress (O2) into the flash gas
  - Previously connected VRUs to tanks directly to tanks
    - <1 psig inlet pressure, create vacuum and pulls air into the flash gas
    - Result O2> 10 ppm exceeding pipeline and facilities specs
    - Downstream operators installing O2 meters and will shutdown on high O2
    - Increase risk of corrosion and solids with H2S present
Vapor Recovery Tower (VRT) - Continued

Vertical Vessel
- 30” to 60” dia. x 30’-40’ tall
- Internal dip tube
- Oil enters top
- Flows to bottom
- Fills vessel
- Pressure pushes oil up the dip tube to oil tanks
- Flash gas leaves top to VRU
VRT Design Continued

- **Original VRU design**
  - Approximately 5 feet above oil tanks
  - Problem upset downstream equipment (VRU)
    - Blow out seal and limited pressure control (<2 psig pressure)

- **VRT design optimization**
  - Snap acting dump valves upset downstream equipment operation (VRU/ VRT liquid levels)
    - Install a large K/O drum on the VRU
    - Increase the overall height of the VRT
      - 10 feet above tanks and some up to 20 feet above tanks
    - Convert to throttling dump valves
  - Install PCV to vent or flare on the VRU to avoid blowing VRT seals
  - Operate VRT at 2-4 psig for good control, prevent air ingress
VRT/VRU System Value – Not Always Economic

ASSUMPTIONS
- $225k installation cost
- $2,500/mo. VRU lease
- 450 BPD IP Rate
- 35 psi secondary separator pressure
- $0.41/BBL gross value of VRT flash gas
- 85/85 POP gathering & processing fee
- Value is sensitive to HP and LP flash pressures
- Value is sensitive to HP and LP flash pressures
Tips on Shale Oil Gas Handling Facility Design

- Heavy gas condenses, can build large recycle
  - Maintain higher temps from VRU coolers with temperature controller
  - Use HPS gas for compressor recycle; helps clear out heavy gas

- Air ingress can bust oxygen specification
  - Use HPS gas for VRU recycle, keep VRU running (no on/off operation)
  - NEVER use VRU’s to pull vapors from storage tanks
Tips on Shale Oil Gas Handling Facility Design (continued)

› ECD capacity
  › VRT/VRU’s capture 90-95% of flash gas
  › ECD’s sized to handle low volume, also full VRU/VRT volume when VRU down

› Design for flexibility
  › Peak vs decline operation
  › Strategic drilling (offset) to optimize facility sizing and cost
Overall there are many opportunities available to better design and operate gas handling equipment.

During this low-price oil environment, it is critical to use this time and available resources to minimize the capital cost of these production facilities and improve the economics of the well.