Low Pressure Operations

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Role of Low Pressure in Well Performance

• Low surface pressures can impact:
  – Inflow rate by lowering BHP
  – Liquid level by increasing gas velocity (to increase liquid-lifting capacity of the gas)
  – Liquid level by lowering dew point and increasing evaporation
• Liquid level is often the controlling factor in production rate from a “dry gas” well:
  – Water exerts 0.43 psi/ft (condensate is somewhat less)
  – 2-3/8 tubing holds 0.162 gal/ft
  – 1/2 bbl (130 ft) of water will increase sand face pressure >50 psi
• Low pressures can have a role in deliquification:
  – Small problems (<20 bbl/MMCF) it can be the whole answer
  – Large problems it can participate in the answer
General Questions

• What constitutes low pressure operations?
  – As pressure drops below 50 psia, the flowing gas begins behaving less like an
    incompressible fluid and the flow stream’s ability to act on the environment
    declines rapidly
  – By 2 atm (11-15 psig) the incompressible flow assumption is invalid and the
gas acts very differently from high pressure gas

• Will piping ingest air during vacuum ops?
  – Probably. Can be reduced by plugging open-ended lines.

• Can ingested air cause the line to blow up?
  – No, you have to be between the LEL and UEL for an explosion.
  – If a well makes 100 MCF/d, you would have to ingest 0.650-2.000 MMCF/d
    of air which would be a very large hole (that couldn’t sustain vacuum
    operations).

• Can ingested air cause corrosion problems?
  – The gathering companies claim that it can but their evidence is REALLY weak

Water Droplets

• Coarse Spray
  – 201-1,000 microns (0.2-1 mm)
  – Terminal velocity as a raindrop 7 ft/s so it
    would tend to fall at separator velocities
  – Will sheet or pool at normal temps

• Fine Spray
  – 101-200 microns
  – Terminal velocity as drizzle 0.5 ft/s (won’t
    tend to fall at sep velocities)
  – Will pool at normal temps

• Mist
  – 51 -100 microns
  – Terminal velocity as fog 0.05 ft/s
  – Will bead at normal temps

• Aerosol
  – 1-50 microns
  – Terminal velocity as cloud 0.003 ft/s
  – Will collect on a mirror at normal temps
Water Vapor

- A water vapor molecule is 0.00038 microns
- If a one micron droplet was blown up to the size of the earth,
  - A water molecule would be 4 ft diameter
  - A methane molecule would be 6.4 ft diameter
- Any filter that can stop a water vapor molecule would not allow a methane molecule through

Evaporation

- Whenever there is a coherent gas/liquid interface, liquid will evaporate until the gas at the surface of the liquid is at 100% relative humidity
- As wellhead pressures diminish, the amount of water that gas can carry as “humidity” increases dramatically

- At 100°F
  - 90 psia holds 1.5 bbl/MMCF
  - 45 psia holds 2.9 bbl/MMCF
  - 23 psia holds 5.6 bbl/MMCF
  - 12 psia holds 10.7 bbl/MMCF
Phase-Change Scale

- Produced water is usually at least 10,000 mg/L TDS
- Flashing a barrel of 10,000 mg/L water deposits 3.5 pounds of solids somewhere
  - NaCl turns into salt blocks (eventually soluble in hot water)
  - Bicarbonate (HCO3) turns into Nahcolite (NaHCO3) that is granite hard and barely soluble in strong acid

Salt Inhibition

- Intent is to form soft, mobile “slurry” instead of rocks and gravel
- The flow stream must have enough energy to move slurry to some convenient location
- Salt inhibition does not work well in gas wells:
  - Surface injection tends to stick to the top of the pipe and not contact downhole liquids
  - Cap string injection doesn’t mix well
- No injected chemical works very well in low pressure gas, but salt inhibitors are especially worthless
  - They can’t prevent evaporation
  - When the liquid evaporates the inhibitor contributes to mass left
Water in Piping

- Standing liquid requires gas to do work
  - Gas wants to drag water surface along the pipe
  - Result is white caps on the water and big pressure drop
- Piping too big leaves water behind.

Considerations for Moving Water from Separator

- Separator Pressures
  - <15 psig, probably can’t dump to an above-ground tank
  - <0 psig can’t dump to a buried pit
- Options
  - Transfer Pump (auto-start required)
  - Remove separator
  - Blowcase
Wells with Downhole Pumps

- Where do you go with a pump discharge?
  - To Separator?
    - Minimum Separator pressure limited to water line pressure unless you have a blowcase or a pump
  - To water line?
    - Every pump makes some gas (some pumps make a lot of gas), you don’t want it in your water system
    - Getting gas out of the water system can be a chore
- There seems to be fewer problems when the pump goes to the water system, but even these can be solved with a gas knock out

Typical Compressor Types

<table>
<thead>
<tr>
<th>Type</th>
<th>Eff Limit</th>
<th>Max Ratio</th>
<th>Typical Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid Ring</td>
<td>40-50%</td>
<td>Disch Press</td>
<td>5</td>
</tr>
<tr>
<td>Eductor/Ejector</td>
<td>40-70%</td>
<td>Power fluid flow rate</td>
<td>10</td>
</tr>
<tr>
<td>Dry Screw</td>
<td>60-72%</td>
<td>Disch Temp</td>
<td>5</td>
</tr>
<tr>
<td>Centrifugal</td>
<td>65-75%</td>
<td>Disch temp</td>
<td>2.5/stage</td>
</tr>
<tr>
<td>Flooded Screw</td>
<td>70-72%</td>
<td>Max suction</td>
<td>10-20</td>
</tr>
<tr>
<td>Recip</td>
<td>78-88%</td>
<td>Rod load or disch temp</td>
<td>4.5/stage</td>
</tr>
</tbody>
</table>
Operating Principles
Recip Compressor

• Recip compressors used since 1800’s (steam driven, air service)
• Pistons moving inside cylinders draw gas in, then raise gas pressure above required discharge
• Recip compressors are categorized by:
  – Number of “throws” (each throw has two compression chambers)
  – Number of stages
  – Separable or integral
  – High speed vs. low speed

Recip Compressor
Suction Pressure

• This cylinder is properly configured for:
  – 1st stage suction 40 psig, discharge 209 psig @ 272°F
  – 2nd stage suction 197 psig, discharge 760 psig @ 298°F
  – 130 MCF/d
  – It has the right clearance and spring stiffness for these conditions
• What happens if a half barrel of water comes into the wellbore and the suction pressure drops to 20 psig (39% at 5,300 ft elevation)?
  – 1st stage discharge 136 psig @ 345°F
  – 2nd stage discharge 760 psig @ 411°F
  – Machine is down on high discharge temp
Flooded Screw Compressor

• First flooded screw made by Howden in 1977
• Male rotor is driven by engine or motor
• Female rotor driven by male rotor
• Oil flood
  - Prevents metal-to-metal contact between rotors
  - Seals area around rotors
  - Lubricates
  - Cools

Flooded Screw

• Oil Selection
  - Mineral Oil: Least expensive, not compatible with liquid hydrocarbons
  - Synthetic Oil: Most expensive, generally has the best compatibility with liquid hydrocarbons and will perform slightly better with adsorbed water
  - Semi-synthetic: Mixture of the other two and has intermediate properties
• Screw oil is hydrophilic and will absorb water vapor
• When the oil absorbs water it:
  - Becomes more viscous
  - Loses lubricity
  - Increases surface tension (allowing bigger droplets to fail to coalesce)
• You have to cook the water out of the oil like a reboiler
  - Adjust oil flow, cooling, and/or discharge pressure to achieve 205-215°F out of the screw
  - Higher temps can damage oil, lower temps don’t cook water out
Flooded Screw Temp Example

• Assume

  – Sea level (atmospheric pressure = 14.73 psia)
  – Methane (κ=1.28, cp=0.52669 BTU/lbm-R, qgas=500MCF/d)
  – Semi-synthetic oil (SG=0.81, cp=0.45 BTU/lbm-R, qoil=40gpm, Tin=180°F)
  – Gas Suction = 0 psig at 80°F
  – Gas Discharge = 50 psig at ???

\[
T_{gas-disch} = T_{gas-suct} \left( \frac{P_{gas-disch}}{P_{gas-suct}} \right)^{\frac{(T_{suct})}{T_{disch}}} = (80 + 460) \left( \frac{50 + 14.73}{0 + 14.73} \right) = 770°F
\]

\[
Q_{gas} = \dot{m}_{gas} c_p \Delta T_{gas} = \frac{500000 \text{ cu ft} / \text{day}}{1 \text{ gal} / \text{min} \times 1 \text{ lbm} / \text{gal} \times 0.52669 \text{ BTU} / \text{lbm} / \text{R} \times (770°F - 540°F) / 24 \text{ hr}} = 11600 \text{ BTU/hr}
\]

\[
\Delta T_{oil} = \frac{Q_{oil}}{m_{oil} c_{oil}} = \frac{11600 \text{ BTU/hr}}{40 \text{ gpm} \times 6.84 \text{ lbm/gal} \times 0.45 \text{ BTU/lbm/R} / 60 \text{ min/hr}} = 15.7°F
\]

\[
T_{in} = T_{in} + \Delta T_{oil} = 180°F + 15.6°F = 195.7°F
\]

Too Cool, can raise discharge to 150 psig or lower q(oil) to 22 gpm or raise oil inlet to 190°F

Compressor Comparison

<table>
<thead>
<tr>
<th>Strengths</th>
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<tbody>
<tr>
<td>Recip</td>
<td>Flooded Screw</td>
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<td>Flooded Screw</td>
</tr>
<tr>
<td>Best use of Hp</td>
<td>Narrow suction range</td>
<td>Moving oil requires energy</td>
<td>Wide range of suction pressures</td>
</tr>
<tr>
<td>-1 stage best</td>
<td></td>
<td>(screw about same efficiency as 2-stage recip)</td>
<td></td>
</tr>
<tr>
<td>-2 stage 8% more hp</td>
<td></td>
<td>Changing cond have little impact</td>
<td></td>
</tr>
<tr>
<td>-3 stage 15% more hp</td>
<td></td>
<td>Operating staff uncomfortable</td>
<td></td>
</tr>
<tr>
<td>Operating staff thinks they understand them</td>
<td>Not tolerant of changing conditions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Few consumables</td>
<td>Valves high maint</td>
<td>Oil is expensive</td>
<td></td>
</tr>
<tr>
<td>Some packagers do field machines well</td>
<td>Difficult to balance stages</td>
<td>Packagers don’t do field machines well</td>
<td></td>
</tr>
<tr>
<td>Rugged and Reliable</td>
<td>High temps</td>
<td>Very low temps</td>
<td></td>
</tr>
<tr>
<td>High maintenance</td>
<td>High maintenance</td>
<td>Low maintenance</td>
<td></td>
</tr>
<tr>
<td>Higher Purchase cost</td>
<td>Lower Purch cost</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Decision

• Small Hp 2- or 3-stage recips are rarely the best choice for wellsite use
  – Can’t afford personnel to optimize small units
  – Sub-optimized units prone to mechanical failures
• Suction
  – Above 40 psig single stage recip generally better
  – Below 40 psig flooded screw considerably better
• Ratios
  – Below 4 ratios single stage recip has better use of Hp
  – Screws work well up to nearly 20 ratios

Eductors/Ejectors

• From the family of thermocompressors that includes Air Ejectors, Evacuators, Sand Blasters, Jet Pumps, and Eductors
• High pressure fluid entrains and boosts the pressure of suction fluid and the combined stream is left at an intermediate pressure
• Ratio of suction pressure to discharge pressure:
  • For an eductor, exhaust pressure limited to about 1.5-3 times suction pressure
  • For an ejector, ratio of exhaust to suction pressure can be as much as 10:1 in absolute terms (psia)
• Efficiency 30-70%
  • More ratios mean better efficiency, but
  • More ratios also means more power fluid required
Casing Flow Control Case

- Uses friction in tubing to drive an ejector
- V-cone monitors tubing flow to stay above critical
- If above critical:
  - Flow cntl valve starts to open, sending power gas to Ejector Tee
  - If csg pressure > 45 #, BP regulator dumps extra
  - Compressor maintains exhaust at 5 psig
- Initial rate 25% higher than before installation (project had an 8 day payout)

Net Positive Suction Head (NPSH)

- Net Positive Suction Head is the amount of external pressure at the inlet to a pump.
- The Required NPSH (NPSH-r) is the amount of external pressure required to ensure the pump operates full of liquid.
- The Available NPSH (NPSH-a) is the amount of external pressure available at the pump suction.
- It generally doesn’t matter if the NPSH comes from an actual hydrostatic head or an applied pressure (as long as the pump sees continuous-phase liquid).
- NPSH-r is very dependent upon fluid properties (mainly the boiling point, and vapor pressure)
## Technologies that evolved from Artificial Lift

<table>
<thead>
<tr>
<th></th>
<th>Typical Capacity (BBL/day)</th>
<th>NPSHr (ft)</th>
<th>Failure method</th>
</tr>
</thead>
<tbody>
<tr>
<td>PCP</td>
<td>4-600+</td>
<td>60-100</td>
<td>Heat of Compression</td>
</tr>
<tr>
<td>Beam Pump</td>
<td>20-500+</td>
<td>75-100</td>
<td>Gas Lock</td>
</tr>
<tr>
<td>Gas Lift</td>
<td>1,000+</td>
<td>200-500</td>
<td>Fall below critical rate</td>
</tr>
<tr>
<td>Jet Pump</td>
<td>10-45+</td>
<td>450-1,000</td>
<td>Cavitation</td>
</tr>
<tr>
<td>ESP</td>
<td>70-1,000+</td>
<td>150-2000</td>
<td>Cavitation</td>
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## Deliquification Technologies

<table>
<thead>
<tr>
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<th>NPSHr (ft)</th>
<th>Failure method</th>
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</thead>
<tbody>
<tr>
<td>Velocity String</td>
<td>&lt;100</td>
<td>0</td>
<td>Well capacity falls below critical</td>
</tr>
<tr>
<td>Tubing Flow Controller</td>
<td>&lt;100</td>
<td>0</td>
<td>Well capacity falls below critical</td>
</tr>
<tr>
<td>Plunger</td>
<td>&lt;20</td>
<td>0</td>
<td>Reservoir pressure falls below min required</td>
</tr>
<tr>
<td>Evaporation</td>
<td>&lt;20</td>
<td>0</td>
<td>Scale plugging formation</td>
</tr>
<tr>
<td>HSP</td>
<td>&lt;150</td>
<td>0</td>
<td>Wear</td>
</tr>
</tbody>
</table>
Conclusion

• Low pressure operations are a pain in the posterior
  (But can be very profitable)
• Every solution to a problem will cause a new problem
  (That may be worse)
• Every symptom is masking another symptom
  (Which is masking still another symptom)
• What worked yesterday may not work tomorrow
  (But may work next month at a different pressure)
• NEVER say “we tried that and it didn’t work”
  (Those words taste nasty when you have to eat them)
• Design for flexibility because you never know what the next problem
  will require

Thank you for your attention.
Additional information can be found at
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