Gas Well Deliquification by Chemical Foam

Workshop 2013

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Craig Adelizzi
Contents

1) Introduction to the theory around gas well liquid loading.
2) Deliquification through the use of chemical foamers.
3) Typical foamer chemistry.
4) Laboratory testing.
5) Foamer technology in the field.
When there is water, there is trouble

Cause
- Water/Hydrocarbon Column
- Water
- High Ion Concentrations in Water

Challenge
- Production Reduction
- Corrosion Risk
- Scale Deposition

Solution
- Foaming Agent (FA)
- Corrosion Inhibitor (CI)
- Scale Inhibitor (SI)

Comb Foamer (FA/CI/SI)

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Introduction to Gas Well Liquid Loading

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Gas Well Liquid Loading

What is gas well liquid loading?
- An accumulation of fluids in the tubing

When does gas well liquid loading begin?
- Gas flow rate insufficient to overcome gravity
- Point where both forces are equal is the critical velocity
Gas Well Liquid Loading

What are the consequences of gas well liquid loading?

- Once fluids build up to the point where the hydrostatic head is equal to reservoir pressure, no production will occur.
Flow Regimes of Vertical Wells

INCREASING GAS RATE

BUDDLY  |  SLUG  |  CHURN  |  WISPY-ANNULAR  |  ANNULAR

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Critical Velocity

\[ V_c = C \frac{(\rho_{\text{Liquid}} - 0.0031p)^{1/4}}{(0.0031p)^{1/2}} \]

- \( p \) = tubing pressure
- \( \rho \) = liquid density
- \( C \) = a constant, depending on pressure, fluids, and surface tension

(calculation based on work done by Turner et al. or Coleman et al.)
Rate Comparison

Actual Rate > Critical Rate

- All fluids should be moving out of the well in entrained droplets or along the annular film.
- Well not considered to be “loading”.
- There can be exceptions.
- Systematic evaluation is the key to identify liquid loading.
Rate Comparison

Actual Rate < Critical Rate

- Some or most fluids are not being carried out of the well
- Well can be considered “loading”
- Liquids will build up in well bore and create some back pressure further reducing flow rate
- Lower flow rates cause more fluid accumulation and this situation will continue to cascade
Signs of Liquid Loading

- Sharp decline in production rate

- Changes in water production
  - Slugs of liquid coming through
  - Decline in produced water

- Changes in pressure differentials
  - Casing minus tubing versus time (limited to packerless completions)
History of a Gas Well

Surface Condition

Initial Production

Stable Flow

Unstable Flow

Stable Flow

Well Dead

Rate

DECREASING GAS RATE

TIME

Non-traditional production enhancement activities, e.g. chemical foamers, velocity strings, wellhead compression, plunger etc.
Problems from Liquid Loading

- Decreased or erratic production and potential topside fluids management difficulties.
- Possible damage or a water block on the formation.
- Increased corrosion risk.
- Requires artificial lift to overcome and extend the well life.
Artificial Lift Options

- **Mechanical**
  - Rod Pumps
  - Submersible Pumps
  - Hydraulic Pumps
  - Plungers
  - Gas Lift
  - Velocity Strings
  - Compression

- **Chemical**
  - Solid Foamers (Soap Sticks)
  - Liquid Foaming agents
Deliquification Through the use of Chemical Foamers

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Where do we see Foam?

- Foam is used extensively everyday
  - Fire-fighting foam
  - Shampoo lather
  - Washing up liquids/detergents

- Foam in the oilfield is normally unwanted
  - Foaming in separators leads to inefficiency
Where do we use Foam?

Use of foaming agents;
- in traditional gas well deliquification
- in hydrocarbon loaded wells
- in coal bed methane production
- in foam squeezes
- in shale production
- in foam drilling (under balanced drilling)
Theory of Foam

Thin Film Region
(Liquid Phase)

Plateau Border

Interface
(2D Surface Phase)

GAS

FOAM

BULK LIQUID

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Theory of Foam

Not all foam is the same
- For unloading of gas wells, a wet foam is required
Foam Density against Critical Velocity

21-35% Reduction in Critical Velocity

Foam density (fraction of liquid density)

Critical velocity, ft/s

\[ V_t = 1.593 \gamma^{1/4} \left( f\rho_l - \rho_g \right)^{1/4} / \rho_g^{1/2} \]

Apparent liquid density
13-16% Reduction in Critical Velocity

Surface Tension against Critical Velocity

\[ V_t = 1.593\gamma^{1/4} \left( f\rho_l - \rho_g \right)^{1/4} / \rho_g^{1/2} \]
Foam against Critical Velocity

Foam can reduce the critical velocity or rate at least by 1/3 to 1/2 by reducing the surface tension and apparent fluid density.

\[ V_t = \frac{1.593 \gamma^{1/4} (\rho_l - \rho_g)^{1/4}}{\rho_g^{1/2}} \text{ ft/sec} \]

A larger reduction can be achieved in the field with proper application in most cases. 60-80% has been seen in some wells.
Chemical Methods for Artificial Lift

- Solid Soap Sticks
  - Soap stick launcher or manually

- Liquid Foamers
Pros and Cons of Solid Foamers

**Pros:**
- Ease of use
- Limited Personnel Exposure (with launcher)
- Availability
- Packaging

**Cons:**
- Limited chemistry
- Chemical regulations (REACH etc)
- Well completion
- Plugging issue
  - Incomplete dissolution
- Production variations (batch only)
- Limited water removal, depends on dimensions, caps out at ~ 50 – 100 BPD
Pros of Liquid Foamers

- Cost effectiveness (low set-up and operating cost).
- Versatility for different completions and environments.
- Can be used to boost mechanical methods.
- Tolerance of particulates, pressure and high temperatures.
- Rapid response from the well.
- Automated continuous programs.
- Customize combination products can control down hole corrosion, scale or paraffin problems.
Cons of Liquid Foamers

- Placement of product can be difficult (ie packered wells, cap-strings)
- Personnel intervention for batch treatments
- Well conditions change could render specific product ineffective
- Temperature stability on surface (cold) and down hole (hot)
- Surface upsets if not optimized (ie foam and OIW)
- Environmental concerns
Foaming Agent Requirements

The main requirement of a foamer is the ability to build a wet foam in the presence of condensate.

Additional requirements might apply:
- Flash point > 61°C
- Meeting environmental requirements
- No negative impact on produced water quality (OiW)
Foaming Agent Requirements

Additional requirements might apply;
- High temperature stability
- Low viscosity at low temperature
- Compatibility with other treatment chemicals, like Defoamer and Water Clarifier

Customers might have additional requirements to take into account;
- Specific test protocols to be met
- Material compatibility toward specific metals or elastomers
- No negative impact on condensate quality
Applications Methods – Batch Treatment

- Batching down the backside
  - Only on packerless completions

- Batch and Fall
  - Good if the well can be “rocked”
  - If there is a very high level of loading

- Bull heading or tubing displacement
  - Use a volume of flush to drive the chemical into location

- Foam Squeeze
  - Can be achieved with liquid or gas and the post-treatment flush
Applications Methods – Continuous

- Drip feed down the annulus
  - If packerless completion

- Capillary strings
  - Depending on completion strings can be run down inside the tubing or banded on the outside of the tubing
  - Various types of atomizers and nozzles available
  - Placement is key to performance
  - Need to ensure that the chemical is delivered to the correct location
  - Typically aim for top perforations
  - Not always easily applicable due to SSSV & integrity requirements

- Can be used in addition to other artificial lift methods
  - Can occur via the gas lift system
What to expect after foamer is applied

- Foamers must have agitation to create foam
- Initial increase in total fluids production
  - More water and condensate
- Increase in production
- Intermittent production should taper off as well unloads
- Potential for foaming and high OIW in topside tanks
  - Foamers are designed to break at the surface after dosage optimization
  - May need to reduce treat rate to optimize performance
- First foam treatment can ‘clean’ the system, mobilizing sand, silt, clay and other solids
Considerations for Foamer Applications

- Thermal Stability
  - Surface
  - Downhole

- Compatibility
  - Metallurgy
  - Fluids
  - Chemical

- Regulatory
  - Environmental
  - Logistics

- Oil/ Condensate/ Water Ratio

- System completion
  - Production Increases
  - Emulsion Tendencies
  - Excess Foaming
  - Chemical Feed Options

- Combination Product Needs
Typical Foamer Chemistry

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Foaming Technology

Yesterday

Yesterday, foamer selection was a lot like fishing. It was an art.

Today

Optimized foamers for natural gas well deliquification: A statistical Design Approach

Tomorrow

Modeling and prediction of foamer performance: A Proactive Approach
Foamer Chemicals

- Surfactants typically applied to aqueous systems.
  - Reduce surface tension
  - Decrease relative density
  - Increases elasticity

- Allows gas/liquid dispersion at a lower gas pressure.
  - In the lamella condensate is trapped

- The benefits.
  - Enables liquid unloading with low set-up cost
  - Customized for local environment
  - Facilitates continuous production
  - Increases gas production
Nonionic surfactant

- Low to medium foaming performance
- Solubility reduces at higher temperatures (cloud point)
- Solubility reduces at higher salt content
- May act as an emulsifier, thereby reducing water quality
- Often applied in foam sticks
- Applied as co-surfactant in formulations
- In general environmentally acceptable
Anionic surfactant

- High foaming performance
- Foaming performances reduces at higher salt content
- In general not stable at high temperature, except sulfonates
- May act as an emulsifier, thereby reducing water quality
- Often applied in high water cut / low temperature wells
- In general toxic to fish, especially the long hydrophobic chain versions
Cationic surfactant

- Moderate foaming performance
- High temperature stability
- Acts substantive (metal surfaces), losing active content to tubing wall
- Might act also as corrosion inhibitor
- Often applied in low condensate wells
- Toxic for organisms
Amphoteric surfactant

- High foaming performance
- Also good foaming performance at high salt content
- Also good foaming performance at medium condensate content
- Excellent temperature stability
- Often corrosive due to presence of chloride as by-product
Combination Products

Most common
- Foamer/Corrosion inhibitor
- Foamer/Scale inhibitor
- Foamer/Corrosion inhibitor/Scale inhibitor

Other options
- Foamer/Salt Dissolver
- Foamer/Halite inhibitor
- Foamer/Paraffin (wax) dispersant or inhibitor
- Foamer/emulsion breaker
- Dry Gas Lift Foamer
Typical Ranges of Combination Products

- **Foaming agent**: 400 ppm – a few %
  - 1%-50% active

- **Corrosion Inhibitor**: 10 - 200 ppm
  - 0.25-9%

- **Scale Inhibitor**: 2 - 50 ppm
  - 0.25%-3%

- Actual dose rates depend on field and sometimes wells, no magic bullet product

- Products might have to be tailored to application
Chemical demand

Required amount of foaming agent added depends on several factors

- **Salinity of water**
  - Salinity increases water specific gravity
  - Charge neutralization

- **Gas flow rate**
  - Closer to critical is less chemical demand
  - Flow speed is more important than composition

- **Contaminants with defoaming action**
  - Solids
  - Hydrocarbon condensates
Potential Defoaming Contaminants

- Disruption of interfacial film structure
  - Displacement of stabilising surfactant – i.e. by corrosion inhibitor

- Spontaneous spreading of oils
  - Low surface tension liquids
  - Positive spreading coefficient

- Physical rupture of lamellae
  - Waxy or hydrophobic particles
  - Oil droplets
Configuration of Oil at the Air/liquid Interface

1. Oil drop inside the solution
2. Oil drop at the surface separated by a pseudo-emulsion film from the air
3. Oil drop enters the gas phase and forms a lens
4. Oil spreads at the solution surface and ruptures the bubble

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Oil Droplet in Lamella

Oil droplet

Cell 1

Cell 2
Lamella Rupture

Surface tension gradient

Cell 1

Cell 2
Escaping Oil Droplet
Defoamer Products

To offer topside process protection a suitable defoamer can be offered

- Silicone based products demonstrated to be very efficient at killing foam in a range of products.
- However silicone free defoamers are also available.

Defoamer products or antifoaming products?
Defoamer or Antifoamer

Defoamer Action

Antifoamer Action
Laboratory Testing

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Laboratory Foaming Test Methods

- **Standard performance tests**
  - ASTM D-3601 - Foam in Aqueous media (Bottle Test)
  - ASTM D-3519 - Foam in Aqueous media (Blender Test)
  - ASTM D-892 - Column/Cylinder Test Method (Dynamic Test)

- **Specialized performance test**
  - Unloading rig
  - Well simulators

- **Customer tests**

- Many test methods, not all are equally representative
  - JIP currently ongoing to evaluate all methods
ASTM D-3601
(Foam in Aqueous media - Bottle Test)

- Quick and cheap test
- Measurement of foam height and life
- Useful for gross determination of “foaminess”
- Established for aqueous, low viscosity system
- Using low shear to generate foam
  - Some foamers are prone to perform better under shear rather than gas flow
- Result is a comparison of foam height and nature versus a control
- Limitation on dynamic system predictability
ASTM D-3519
(Foam in Aqueous Media - Blender Test)

- Foam characterization under high shear conditions, which promotes stable foam
- High shear can “shear” some foam thus could lower foam height (dependent on surfactants used)
- Hydrocarbon influences difficult to assess due to affect on foam height and emulsification issues
- Some surfactants prone to generate more foam in high shear conditions
ASTM D-3519 (Foam in Aqueous Media - Blender Test)

- Ether sulfates prone to generate more foam than amphoteric surfactants

- Gas volume ratios vs. foam height

- Ether sulfate 1500 ppm
  - Foam height 600 ml
  - Half time 1m 25s

- Amphoteric 1500 ppm
  - Foam height 520 ml
  - Half time 1m 10s
ASTM D-3519
(Foam in Aqueous Media - Blender Test)

- Useful for foam characterization under high shear conditions
- Limited value to dynamic well unloading, not predictive
- Use for surfactant comparison for well unloading dependent on what characteristic of foam being investigated
- Hydrocarbon influences cannot be considered because the foam height will be severely reduced
ASTM D-892 & Modifications (Column/Cylinder Test Method – Dynamic Test)

Data Collected

- Foam height versus Time
- Fluid carry over with given gas rate (0.01–10 ft/sec)
- Foam life
- Drainage half life
ASTM D-892 & Modifications (Column/Cylinder Test Method – Dynamic Test)

Modifications

- Heating the liquid to provide more representative conditions
- Changes the size of the cylinder – gives different ID
- Still assess the same properties
ASTM D-892 & Modifications (Column/Cylinder Test Method – Dynamic Test)

At high gas rate, foam characteristics become more dynamic and better simulates real deliquification conditions

- Metastable foam, foam film drainage, foam slugs
- Could be used with hydrocarbon
- Can be used to rank surfactant chemistries
- Predictability of foaming ability of surfactants in dynamic conditions
- No preset criteria of “pass” but can put minimum overflow (unloading) dependent on system
ASTM D-892 (Dynamic Unloading Rig - modified)

Unloading Efficiency (%) = \( \frac{W_{\text{unloaded}}}{W_{\text{initial}}} \times 100 \)
ASTM D-892 (Dynamic Unloading Rig - modified)

Other data accessed can include: foam built-up time, volume, stability etc.
ASTM D-892 Dynamic Unloading Rig - modified

- Foam characteristics generated under dynamic conditions and better simulates deliquification conditions
- Can be used to quantitatively rank the performance of surfactants
  - Predictability of foaming ability of surfactants in dynamic conditions
  - Can be used to with hydrocarbon
  - Can be used to predict minimum dosage to achieve unloading
  - Can be tested at limited elevated temperatures
Well Simulator
Well Simulation Deliquification

Critical Lift Concentration Curves

\[ y = -0.1872x^2 + 29.602x \]

\[ y = -0.1328x^2 + 21.005x \]

\[ y = -0.0671x^2 + 10.613x \]
Taking Technology To The Field

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Taking Technology To The Field

1. **ANALYZE**
   - Analyse Field
   - Historical production data
   - Well downtime history
   - Well shut-in and flowing parameters

2. **MODEL**
   - Model Well
   - Address actual field parameters that basic models do not address
   - Evaluate the severity of liquid loading

3. **RANK**
   - Rank Wells
   - Determine and rank by the probability of success
   - Rank by impact in increased gas production

4. **RECOMMEND**
   - Provide Specialized Product Recommendation
   - Consider BHT, completion, salinity, % hydrocarbon, pour point
   - Propose most suitable application methods

5. **EXECUTE**
   - Apply Technology in the Field
   - Use a systematic, scientific approach to maximize production while controlling costs
   - Increase production, reduce downtime, improved decline curve
Product Selection Criteria

- **Produced Fluid Characteristics**
  - Salinity, hardness, temperature, condensate, oil

- **Reservoir/Well Conditions**
  - Quality and stability at reservoir conditions (T, p)

- **Product Secondary Properties**
  - Foam viscosity, freezing point, cloud point, wet/dry

- **Fluid compatibility**

- **Availability of demulsifier, defoamer (if needed)**

- **HS&E issues**

- **Proper application method**
  - Batch vs Continuous
Modeling Input
✓ Input sheet requests production data and well diagram
✓ Ability to predict increased gas return and fluids increase
✓ Remember, bad data in = bad data out!
Modeling Output

<table>
<thead>
<tr>
<th>Well</th>
<th>Well A</th>
<th>Well B</th>
<th>Well C</th>
<th>Well D</th>
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<tbody>
<tr>
<td>STATIC BHP (Calculated) Bar</td>
<td>65</td>
<td>95</td>
<td>30</td>
<td>62</td>
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<tr>
<td>FLOWING BHP (Estimate Only!) Bar</td>
<td>281</td>
<td>435</td>
<td>322</td>
<td>367</td>
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<td>CRITICAL VELOCITY RATE SM3/D</td>
<td>22209.91</td>
<td>62250.62</td>
<td>64.01</td>
<td>38933.89</td>
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<td>0.00</td>
<td>0.00</td>
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<tr>
<td>WHAOF SM3/D</td>
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<td>82754.56</td>
<td>165005.14</td>
<td>79607.77</td>
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<td>0.91</td>
<td>0.51</td>
<td>0.86</td>
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<td>TARGET WHAOF %</td>
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<td>1.00</td>
<td>1.00</td>
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<td>TARGET INCREASE SM3/D</td>
<td>3373.75</td>
<td>7058.76</td>
<td>80716.23</td>
<td>11394.60</td>
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<tr>
<td>CURRENT GLR SM3 / M3</td>
<td>8698.60</td>
<td>15814.92</td>
<td>14730.40</td>
<td>1804.32</td>
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<tr>
<td>% OIL</td>
<td>3%</td>
<td>30%</td>
<td>62%</td>
<td>2%</td>
</tr>
<tr>
<td>% WATER</td>
<td>97%</td>
<td>70%</td>
<td>38%</td>
<td>98%</td>
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<tr>
<td>TOTAL FLUID INCREASE M3/D</td>
<td>0.01</td>
<td>0.01</td>
<td>0.14</td>
<td>0.16</td>
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<td>TARGET DAILY FLUID PROD. M3/D</td>
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<td>0.28</td>
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<td>0.16</td>
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Total Cost of Ownership Evaluation

Costs
- Installation
  - Cap strings
  - Tanks
  - Pumps
  - Injection tubing
- Chemical
  - Delivery costs
- Manpower
  - Time opening/closing wells
- Production downtime
- Production decline
- Costs of alternatives

Advantages
- Safety
  - Dangerous equipment
- Manpower
  - Can deploy manpower elsewhere
- Equipment
  - VS. other methods
  - Combination products
- Corrosion/scale inhibition
- Salt inhibition – no shut-in time
- Costs of alternatives

Increased revenue
- Production gains
- Less downtime
Unloading of Horizontal Gas Well (I)

Flow Back Results

- Liquid (bbls/day)
- Gas Production (MMscf/Day)

<table>
<thead>
<tr>
<th>Date</th>
<th>Liquid (bbls)</th>
<th>Gas Production (MMscf)</th>
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</thead>
<tbody>
<tr>
<td>28th May</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>29th May</td>
<td>100</td>
<td>1</td>
</tr>
<tr>
<td>30th May</td>
<td>200</td>
<td>2</td>
</tr>
<tr>
<td>31st May</td>
<td>300</td>
<td>3</td>
</tr>
<tr>
<td>1st June</td>
<td>400</td>
<td>4</td>
</tr>
<tr>
<td>2nd June</td>
<td>500</td>
<td>5</td>
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<tr>
<td>3rd June</td>
<td>600</td>
<td>6</td>
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<tr>
<td>4th June</td>
<td>700</td>
<td>7</td>
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<tr>
<td>5th June</td>
<td>800</td>
<td>8</td>
</tr>
<tr>
<td>6th June</td>
<td>900</td>
<td>9</td>
</tr>
<tr>
<td>7th June</td>
<td>1000</td>
<td>10</td>
</tr>
</tbody>
</table>

Graph showing the increase in gas production and liquid production over time from May 28th to June 7th.
Well production increased by;

3.5 MMscf/d average over 27 days

Barrels of fluids removed from well under its own power;

1600 bbl per day

Wells sometimes require multiple batches to kick off either due to large volume of liquids in the tubing, casing, or near well bore area.
Application Trouble Shooting

Emulsion Formation
- Surfactants can potentially increase emulsion tendencies
- Foamer treatments can be managed with antifoam and emulsion breakers as required
- Field evidence demonstrates no impact on process

Process Upsets
- Proper topside foam control should prevent any disruptions
- Optimum foamer dosage and correct defoamer application if needed
- No reported impact on water quality specification

No Well Response
- Dead well
  - Insufficient gas or agitation
  - Can rock or swab the well
  - Apply gas sticks / pellets – introduce localized gas
- Flowing well
  - Chemical not reaching the liquids
  - Well conditions are not conducive to loading
  - Modelling error

Capstring Issues
- Plugging of the line
  - Use only capstring certified products
  - Apply appropriate flushing procedures for shut down
- Compatibility
  - Materials
  - Chemicals
  - Produced fluid
  - Thermal stability
Summary Of Foaming

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Opportunities for Onshore Applications

- Set up costs are low compared to other deliquification methods
- Potential to take well all the way to abandonment
- Some synergy with other mechanical methods
- Combination products provide one solution to multiple problems
Challenges for Onshore Applications

- Placement of soap stick launchers or caps strings can be difficult
- Environmental and material compatibilities must be considered
- Temperature stability of the foamer might be an issue in very hot wells.
Challenges for horizontal applications

Where to inject the Foamer?

- Foamers work best in elbow region
- Inject as close to the elbow as possible
- Horizontal area difficult to foam unless injection can be right on a slug point
Challenges for offshore applications

- Quality of produced water critical parameter, the use of a water clarifier might be required to keep water in spec

- Handling of large volumes of produced fluids after a foamer batch might overwhelm separation trains; fluid production might have to be limited
Summary

- Foam will greatly facilitate the removal of fluids from the well
- As fluids are removed from the well, gas rate can increase causing a higher gas velocity and thus increasing the amount of fluids removed
- Foamers are easy to use and generally user friendly
Summary

- Compatibility of fluids with Foamers should be tested beforehand on lab scale.
- Choosing the right wells and application method is important.
- Offshore additional challenges apply.
- Foamers can be used to boost other unloading techniques.
When there is water, there is trouble

- Water/Hydrocarbon Column
  - Challenge: Production Reduction
  - Solution: Foaming Agent (FA)

- Water
  - Challenge: Corrosion Risk
  - Solution: Corrosion Inhibitor (CI)

- High Ion Concentrations in Water
  - Challenge: Scale Deposition
  - Solution: Scale Inhibitor (SI)

Comb Foamer (FA/Ci/Si)

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Thank you

With thanks to co-authors;
Fenfen Huang
Jaclyn McFadzean
Scott Caird