Corrosion and Production Chemistry Issues Induced by Artificial Lift Methods

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Outline

• Artificial Lift Methods - Common Issues
• Cases:
  – Plunger Lift – Corrosion Analysis
  – ESP – Scale Analysis
  – Plunger Lift – Salt Drop Out
• Summary and Recommendations
Artificial Lift Methods - Prod. Chem Issues

- Plunger Lift – Corrosion/mechanical damage, solids drop-out
- ESP – Scale/salt drop out, asphaltenes, corrosion
- Rod Pumping - Corrosion
- Hydraulic Piston/Jet – Scale
- Gas Lift – Inorganic/organic solids, hydrates
- Progressive Cavity – Erosion/corrosion, material incompatibility
Plunger Lift – Corrosion Case Background

- Intermittent production mostly with plunger lift
- Ran caliper surveys annually to determine corrosion rates in number of wells representing fields
- Corrosion rates vary from 5 mpy to 30 mpy
- Location of solids build-up varies depending well conditions, FeCO$_3$
- Pitting attacks usually occur where the plunger rattles or hits collars during rising and falling
- Failures are usually near joints
- Downhole batch corrosion inhibitor treatment
Plunger Lift – Corrosion
Calculation Parameters – Fluids Data

- WHT = 100 °F, BHT= 200 °F
- WHP = 350 psia, BHP = 2000 psia
- Calculations basis:
  - 3.5 bwpd
  - 10 bopd
  - 76 Mcf/d
- Gas Composition:
  - 3% CO₂, 78% C1, 11%C2,
  - 4% C3, 1.7% C4, 0.8%C5, 1.5%C6+

<table>
<thead>
<tr>
<th>WATER COMPOSITION, mg/l</th>
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</thead>
<tbody>
<tr>
<td>Ba^{++}</td>
</tr>
<tr>
<td>Ca^{++}</td>
</tr>
<tr>
<td>Fe^{+2 or 3}</td>
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<tr>
<td>Mg^{++}</td>
</tr>
<tr>
<td>Na^{+}</td>
</tr>
<tr>
<td>Sr^{++}</td>
</tr>
<tr>
<td>HCO₃⁻</td>
</tr>
<tr>
<td>Cl⁻</td>
</tr>
<tr>
<td>SO₄^{--}</td>
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<tr>
<td>pH</td>
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</table>
Corrosion Rate Results with Full Well Stream – No Plunger

Corrosion Rate for 76 Mcf Gas - 10 bbl Oil - 3.5 bbl Water: Velocity 100 ft/min

Corrosion Rate [milyr] - Pressure = 100.000 psia
Corrosion Rate [milyr] - Pressure = 400.000 psia
Corrosion Rate [milyr] - Pressure = 700.000 psia
Corrosion Rate [milyr] - Pressure = 1000.000 psia
Corrosion Rate [milyr] - Pressure = 1300.000 psia
Corrosion Rate [milyr] - Pressure = 1600.000 psia
Corrosion Rate [milyr] - Pressure = 1900.000 psia
Corrosion Rate [milyr] - Pressure = 2200.000 psia
Corrosion Rate [milyr] - Pressure = 2500.000 psia

Temperature [°F]

Corrosion Rate
Corrosion Rate Results with Full Well Stream – No Plunger

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2011 Gas Well Deliquification Workshop
Denver, Colorado
Estimation of Corrosion Rates with Plunger

- Plunger cycle per day is 5; 25 min cycle and 260 min well shut-in times
- Estimated corrosion rates for each step at **A Mid-point Condition of 140 °F and 700 psia**
- Considered phase behaviors at downhole, mid-point and wellhead conditions
- Corrosion rates are calculated using likely fluid compositions and velocities
## Corrosion Rates with Plunger Lift - Calculated for 140°F & 700 psia

### ESTIMATED CORROSION AT A LOCATION WITH Temp = 140°F Temperature and 700 psia Pressure

<table>
<thead>
<tr>
<th>Step #</th>
<th>Description</th>
<th>Fluid Mixture @ Scales</th>
<th>Velocity, ft/min</th>
<th>Duration, min</th>
<th>Number of Days per year</th>
<th>Step Corrosion Rate @ 140°F &amp; 700 psia, mpy</th>
<th>Per Year Net Contribution to Corrosion Rate, mpy</th>
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<tr>
<td>1</td>
<td>Plunger Rising</td>
<td>High Liquid and low gas at BHT &amp; P</td>
<td>400</td>
<td>20.0</td>
<td>25.35</td>
<td>15</td>
<td>1.04</td>
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<td>500</td>
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<td>20.28</td>
<td>16</td>
<td>0.89</td>
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<td></td>
<td></td>
<td></td>
<td>600</td>
<td>13.3</td>
<td>16.90</td>
<td>17</td>
<td>0.79</td>
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<td></td>
<td></td>
<td>CaCO$_3$, FeCO$_3$, SrCO$_3$</td>
<td>800</td>
<td>10.0</td>
<td>12.67</td>
<td>19</td>
<td>0.66</td>
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<td></td>
<td>1000</td>
<td>8.0</td>
<td>10.14</td>
<td>20</td>
<td>0.56</td>
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<tr>
<td>2a</td>
<td>Plunger @ Rest/Gas Moving up</td>
<td>High Gas-Very Low Liq Gas separated @ BHT &amp; No Scale</td>
<td>200</td>
<td>40.0</td>
<td>50.69</td>
<td>230</td>
<td>31.94</td>
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<td></td>
<td>400</td>
<td>20.0</td>
<td>25.35</td>
<td>292</td>
<td>20.28</td>
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<td>20.28</td>
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<td>18.00</td>
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<td>800</td>
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<td>12.67</td>
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<td>2b</td>
<td>Plunger @ Rest/Gas Moving up &amp; Limited Liquid Draining</td>
<td>High Gas-Low Liq FeCO$_3$, BaSO$_4$</td>
<td>200</td>
<td>40.0</td>
<td>50.69</td>
<td>101</td>
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<td></td>
<td>300</td>
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<td>115</td>
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<td>3</td>
<td>Plunger Falling</td>
<td>Limited Liquid separated @ wellhead conditions</td>
<td>100</td>
<td>80.0</td>
<td>101.39</td>
<td>0.24</td>
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<td></td>
<td>200</td>
<td>40.0</td>
<td>50.69</td>
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<td>33.80</td>
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<tr>
<td></td>
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<td>CaCO$_3$, FeCO$_3$, SrCO$_3$</td>
<td>400</td>
<td>20.0</td>
<td>25.35</td>
<td>0.24</td>
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### ESTIMATED AVERAGES

<table>
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<tr>
<th></th>
<th>CR Option 2a, mpy</th>
<th>CR Option 2b, mpy</th>
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<tr>
<td>CR Option 2a, mpy</td>
<td>19</td>
<td>12</td>
</tr>
<tr>
<td>CR Option 2b, mpy</td>
<td>37</td>
<td>46</td>
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Field observed corrosion rates in plunger lift operated wells can be estimated by considering prolonged shut-in and short run times.

Corrosion rates in plunger operated wells can be higher but overall yearly rate could be lower if removal of the protective deposits/scales can be prevented.

Solids deposit are generally Fe and Ca carbonates.

Higher corrosion rates in early life of tubing can be due to higher cycle frequency and higher production.
ESP Scale Analysis – Background

• ESP failed within a short time
• Solids captured from the ESP showed
  – 32% CaSO$_4$
  – 26% CaCO$_3$
  – 7% NaCl
  – 4% SrSO$_4$
  – 5% Others
  – 26% organics

• QUESTION: Source(s) of scales (formation and/or Kill Fluid) and at what conditions
• Tight gas sand reservoir with about 10% carbonate
• BHT = 160-165 °F
• BHP > 4000 psia
• Production rates
  – 300 bwpd
  – 150 bopd
  – 0.9 MMcf/d gas
  – CO₂<0.1%

• Formation water and
  Kill fluid compositions

<table>
<thead>
<tr>
<th>ELEMENTS</th>
<th>CONCENTRATION, mg/l</th>
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<tr>
<td></td>
<td>Formation Water</td>
</tr>
<tr>
<td>Barium</td>
<td>Ba⁺⁺</td>
</tr>
<tr>
<td>Calcium</td>
<td>Ca⁺⁺</td>
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<tr>
<td>Iron</td>
<td>Fe⁺² or ³</td>
</tr>
<tr>
<td>Magnesium</td>
<td>Mg⁺⁺</td>
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<tr>
<td>Potassium</td>
<td>K⁺</td>
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<tr>
<td>Sodium</td>
<td>Na⁺</td>
</tr>
<tr>
<td>Strontium</td>
<td>Sr⁺⁺</td>
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<tr>
<td>Bicarbonate</td>
<td>HCO₃⁻</td>
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<tr>
<td>Chloride</td>
<td>Cl⁻</td>
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<tr>
<td>Sulphate</td>
<td>SO₄⁻</td>
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<tr>
<td>Carbon Dioxide</td>
<td>CO₂</td>
</tr>
<tr>
<td>pH</td>
<td></td>
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</table>
ESP Scale Analysis (Cont)
Pressure & Temperature Profiles

- Pre ESP: $T = 161 \, ^0F \, \& \, P = 4039 \, \text{psia}$
- With ESP: $T = 176 \, ^0F \, \& \, P = 1735 \, \text{psia}$
ESP Scale Analysis (Cont)
Cases and Conditions Examined

• Scale prediction modeling with following fluids
  – Total well stream alone in production mode
  – Kill Fluid injection – mixes with reservoir fluid
  – Kill Fluid in reservoir both fresh and contacted with reservoir rock (dissolves carbonates, pH increases)
  – Kill Fluid flowback alone
  – Kill Fluid production followed by reservoir stream

• Conditions
  – Pre ESP: T = 161 \(^{\circ}\)F & P = 4039 psia
  – With ESP: T = 176 \(^{\circ}\)F & P = 1735 psia

• Also Examined
  – Temperature range: 100 - 225 \(^{\circ}\)F
  – Pressure range: 100 – 5000 psia
ESP Scale Analysis – Key Results
Production of Well Stream

- Total Solids & Calcite Scales **Per 1 bbl of Well Stream** - Pre ESP and ESP Operating Conditions

![Graph showing Total Solids & Calcite Scale for 1 bbl of Well Stream at 4039 & 1735 psia](image)
Total Solids & Calcite Scales for **Daily Well Stream** - Pre ESP and ESP Operating Conditions
ESP Scale Analysis – Key Results
Production of Well Stream

- Total Solids & Potential Scales for Pre ESP and @ ESP Operating Conditions, per 1 bbl of Well Stream

![Graph showing total solids and potential scales for 1 bbl of well stream at 4039 & 1735 psia.](image)
ESP Scale Analysis – Key Results
Production of Kill Fluid & Well Stream

Mixing of Reservoir Fluid with Completion Brine @ 180 F & 1735 psia - Production Mode at ESP Inlet - Total Fluid 1 bbl

- Calcium sulfate - Sol [lb]
- Strontium sulfate - Sol [lb]
- Calcium carbonate (calcite) - Sol [lb]
- Strontium carbonate - Sol [lb]
- Barium sulfate - Sol [lb]
ESP Scale Analysis – Key Results
Production of Kill Fluid & Well Stream

Mixing of Reservoir Fluid with Completion Brine @ 161°F & 4039 psia - Production Mode - Total Fluid 1 bbl

Mixing of Reservoir Fluid with Completion Brine @ 175.6°F & 1735 psia - Production Mode at ESP Inlet - Total Fluid 1 bbl

Mixing of Reservoir Fluid with Completion Brine @ 185°F & 1735 psia - Production Mode at ESP Inlet - Total Fluid 1 bbl

Mixing of Reservoir Fluid with Completion Brine @ 200°F & 1735 psia - Production Mode at ESP Inlet - Total Fluid 1 bbl
ESP Scale Analysis – Key Results
Production of Kill Fluid & Well Stream

86% Well Stream & 14% Kill Fluid

Dominant Solids

Temperature [°F]

Calcium carbonate (calcite) - Sol [lb] - Pressure = 4039.00 psia
Calcium carbonate (calcite) - Sol [lb] - Pressure = 1735.00 psia
Calcium sulfate - Sol [lb] - Pressure = 4039.00 psia
Calcium sulfate - Sol [lb] - Pressure = 1735.00 psia
Strontium sulfate - Sol [lb] - Pressure = 4039.00 psia
Strontium sulfate - Sol [lb] - Pressure = 1735.00 psia
Barium sulfate - Sol [lb] - Pressure = 4039.00 psia
Barium sulfate - Sol [lb] - Pressure = 1735.00 psia
ESP Scale Analysis – Key Results
Production of Kill Fluid & Well Stream

70% Well Stream & 30% Kill Fluid

80% Well Stream & 20% Kill Fluid

86% Well Stream & 14% Kill Fluid

90% Well Stream & 10% Kill Fluid
Calculations show that scales are likely to form at ESP inlet caused by both decreasing pressure and increasing temperature.

Compositions and quantity of scales are controlled by not only formation water but also Kill Fluid, formation rock and hydrocarbon compositions.

Scales obtained from ESP were likely to be caused upon mixing of formation brine with Kill Fluid at ratio of 0.8 to 0.9 (formation brine/Kill Fluid) at inlet temperature range of 180 °F - 200 °F.

Kill Fluid should have sufficient scale inhibitor to prevent incompatibility with formation brine; pH adjustment to have no self scaling may not be sufficient.

Detailed evaluation of all potential production conditions under realistic conditions is essential to understand potential solids deposition in ESP lift systems, preventive measures such as scale inhibitor injection should be implemented.
Summary and Recommendations

• In artificial lift selection process, corrosion and production chemistry issues are generally overlooked.

• Critical evaluation of all aspects of artificial lift methods is essential for their successful implementation in fields. Proper use of modeling tools can help to avoid failures.

• Many of the artificial lift methods can cause scaling/salting conditions, however preventive measures are readily available and must be employed.

• Preventive measures include proper formulation of Kill Fluids, batch or continuous scale inhibitor and/or dilution water injection.

• Corrosion failures in plunger lift wells generally occur near joints due to continuous removal of protective passive layer. Focus should be on better design of joints.

• Corrosion rates in plunger operated wells can be higher but overall yearly rate could be lower if removal of the protective deposits/scales can be prevented.
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