Surfactant Stimulation in Offshore Horizontal Wells to Improve Polymer Injectivity for Captain Field EOR

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Captain Field surfactant stimulation of multiple offshore horizontal injection wells

Chemical EOR for injectivity enhancement

- What: Surfactant-polymer stimulation
- Why: Injectivity benefits
- How: Screening, Design, Execution, Results
- Learnings and applicability for both waterflood and polymer flooding

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Surfactant-polymer stimulation definition

Mobilize trapped oleic phase in pores around injector to remove relative permeability effects

- Enables ~100% aqueous injection [water or polymer] (single phase)
- Reduced near wellbore ΔP skin/damage (no capillary pressure)
- Highest potential matrix injectivity (single-phase permeability)

Oil is released further from wellbore, where injectivity is less impacted by oil saturation
Injectivity benefits

Injectivity issues plague many wells in assets. SP stimulations may offer a cost-effective solution for improving injectivity which reduces risks associated with high injection pressures.

### Good Capital Stewardship:
- Low-cost alternative to redrill
- Proven with stimulation vessel and minor facility modifications
- OPEX, not CAPEX

### Good Reservoir Management:
- Increase $k_{rw}$ endpoint and injectivity above a new drilled well
- Maintain higher processing rates
- Reduce subsurface integrity risks

**Illustration of stimulation benefits to pressure, rate and cumulative fluid injected**

![Graph showing the benefits of SP stimulations on injection BHP, rate, and cumulative fluid injected.](image_url)
# Identifying damage mechanism

## Mechanism

<p>| | |</p>
<table>
<thead>
<tr>
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<tbody>
<tr>
<td>1.</td>
<td>Poor water quality (OIW, TSS, bacteria, etc.)</td>
</tr>
<tr>
<td>2.</td>
<td>Polymer crosslinking damage</td>
</tr>
<tr>
<td>3.</td>
<td>Polymer molecule damage</td>
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<tr>
<td>4.</td>
<td>Polymer oil phase damage</td>
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<tr>
<td>5.</td>
<td>Mechanical skin damage (D&amp;C, sand shifting, fines, etc.)</td>
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<tr>
<td>6.</td>
<td>Poor polymer mixing*</td>
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## Diagnostic

<p>| | |</p>
<table>
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<tr>
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<tbody>
<tr>
<td>1.</td>
<td>Field confirmed - injectors use same produced water stream, field data shows oil in water</td>
</tr>
<tr>
<td>2.</td>
<td>Lab refuted – based on measurements with field product</td>
</tr>
<tr>
<td>3.</td>
<td>Lab confirmed – no large measure of damage (even in tight surrogate rock experiments)</td>
</tr>
<tr>
<td>4.</td>
<td>Lab confirmed – significant damage contribution (coreflood face plugging)</td>
</tr>
<tr>
<td>5.</td>
<td>No way to confirm/deny in lab. A field coil tubing acid job showed low improvement to injectivity</td>
</tr>
<tr>
<td>6.</td>
<td>Field confirmed – stimulation wellhead fluid observations and ILT gels afterwards (C52)</td>
</tr>
</tbody>
</table>

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*Remove oil phase damage (from 1 and 4) with surfactant-polymer solution*

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*recognized as strong injectivity decline mechanism after C52 stimulation*
chemical and facility design requirements
(need a workable solution for both)

CHEMICAL
Surfactant to solubilize oil saturations
Polymer to provide fluid mobility control
Phase behaviour to formulate
  • Solubilization ratio
  • Compatibility with reservoir fluids
Commercial supply chain and registration

FACILITY
Tie-in point to injection water
Hanger for vessel-platform hose connection
Polymer mixing capability (from concentrate)
Vessel communications and simultaneous operations

Phase behavior scan: fluid interface changes
Phase behavior data: plot of oil-water solubilization
Captain design challenges

Captain Field application

- Closed system with 200ppm crude oil (OIW)
- $S_{or} = 17\text{-}27\%$ crude oil
- Liquid polymers are 30\text{-}50\% mineral oil
- Tracers to verify well communication
- Constant salinity without gradient $\rightarrow$ Winsor type 1
- Deployment from vessel at low rates

*Phase trapping illustration from SPE 179657*

*Phase separation in neat liquid polymer product*
Polymer injection mobility

• Target displacement of viscous emulsions created
• Mobilize phase damage away from wellbore
• Viscosity needed to compensate for improved relative permeability of injection fluid (higher mobility)

![Graph showing emulsion viscosity vs. concentration and water fraction.](image)

- Polymer designed to mobilize peak emulsion viscosity
- Steps in polymer viscosity to ensure pressure stays below the maximum limit
Facility execution – stimulation vessel and platform

- Injection from a stimulation vessel during suitable weather
- Acid tank neutralization, flushing procedure and quality control
- Hose hanger installed on platform for chemical transfer line
- Temporary pipework rigged up on platform to dose into injection line

SLB Big Orange XVIII connecting to Captain platform
Chemical execution – fluids prepared and injected

TOP: field chemical samples  BOTTOM: C43 wellhead samples (demonstrating flowline clean-out)
Field surveillance, analysis and optimization

- Capture well performance data from meters and gauges
- Real-time wellhead fluid sample tests
- Onsite analysis and optimization of fluid rates
- Make better decisions and ensure execution matches design

Patent number: 10168265

Chevron PMU for offshore core floods and wellhead fluid testing described in SPE190329
Captain surfactant stimulation #1 (C43)
Objective: prove chemical concept in most expendable polymer injection well

- 100% injectivity increase
- 1st offshore surfactant stimulation in a long horizontal injector
- Only 200 bbls of surfactant chemical formulation created a sustainable 2X injectivity for over 7 months in 4000+ft horizontal completion
Captain surfactant stimulation #2 (C52)
Objective: prove chemical repeatability and improve performance and efficiency

- 3X injectivity increase
- Achieved better improvement than C43, in a longer completion
- Decline after stimulation was confirmed to be poor polymer mixing throughout well-life
Captain surfactant stimulation #3 (C60)
Objective: establish performance improvement for polymer flood

Surfactant Stimulation
• Injected surfactant-polymer package, one dilution step
• 2500bbls surfactant fluid – April 2018
• Logged saturation and outflow profile – Sept 2018

Results
• Injectivity improvement → >40% uplift
• Volume → normalized formula volume required per foot
• Longevity → sustained max injection for 4+MMbbls
• Saturation log → 6-11% across entire completion
• Payout → cash positive in < 8 months online

Saturation log results: Sorc below Sorp in all wellbore

Injection rate results: Plan versus Actual
Summary

Conclusions
- Surfactant-polymer stimulation successfully increases injectivity
- Chemical and facility design provided good field execution
- Polymer was necessary to mobilize emulsions

Opportunities realized
- Higher injectivity and processing rates
- Avoid re-drilling injectors
- Operate under safer conditions

Path Forward:
- Batch treatment of injection wells
- Use on waterflood injector(s)
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