Slugging Reduction and Production Enhancement by Emulsion Breaker Injection in Gas Lifted Wells. Ekofisk Case.

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Problem statement

• Most of GEA wells over the time start to produce at low bottom hole, become heavy and hence start slugging

• Slugging leads to extensive fluctuations in process facilities which has negative impact at separation, instrument control, oil metering, etc.

• Slugging can have a negative impact at production

Fig. 1. Example of slugging development over time
Solution

- Slugging can be improved by application of emulsion breaker injection in gas lift system
- Reduced viscosity gives less pressure drop across the tubing and hence well shows more stable flow
- VRA – Viscosity Reducing Agent

Fig. 2. Example of VRA impact at well slugging
## Project History

| Pilot 1 | 2016 | Evaluated applicability and identified potential candidates for the trial  
Performed Pilot 1. Proof of concept obtained.  
**Tech worked, but was not applicable for all wells** (25% success) |
| --- | --- | --- |
| Pilot 2 | 2017-2018 | Developed simulation model for screening of the new candidates  
Completed well integrity impact evaluation  
Performed 10 days field trial – “Pilot 2” at 7 Ekofisk wells  
**Observed sustained slugging reduction & variable production uplift with higher success rate** (70%)  
Recommended to test all wells prior to permanent implementation |
| Pilot 3 | 2019-2020 | Developed semi-permanent testing facility design  
Performed environmental impact evaluation and obtained NEA permission  
**Started Pilot 3 Nov. 2020** |
<table>
<thead>
<tr>
<th>Well</th>
<th>Δ Oil, bopd</th>
<th>Δ Water, bwpd</th>
<th>Δ Total Liquid, %</th>
<th>Water Cut Prior, %</th>
<th>Water Cut After, %</th>
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<tbody>
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<td>Well 1</td>
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<td>+187</td>
<td>+5.5</td>
<td>88.6</td>
<td>90</td>
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<tr>
<td>Well 2</td>
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<td>Well 3</td>
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<td>+642</td>
<td>4-8</td>
<td>-</td>
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</table>
Sensitivity to concentration

- Wells showed immediate response to EB injection in gas lift
- Production uplift was impacted by initial flush
- Uplift was sensitive to chemical concentration

Fig. 3. Sensitivity of chemical dosage
PILOT 3 scope

- Plan is to test EB injection for all gas lifted wells at all GEA production platforms
- Injection in up to 4-6 wells at the same time per platform
- After 5 days of injection, decision will be taken to continue or to stop VRA injection in particular well based on observed impact
- If VRA effect will be observed - injection in particular well will be continued & stopped after 3 months
- Goal is to quantify production uplift & define number of wells which will be included in business case for permanent implementation (uplift vs OPEX cost of permanent injection)
Conclusions

• Emulsion breaker injection in gas lift is a successful technique but is not applicable for all wells and the candidate selection method is critical

• In the two trials, sustained slugging reduction and variable production uplift was observed in some wells: 25% of wells in the first pilot and 70% of wells in the second pilot

• Where successful, 4-8% liquid uplift was achieved
  • Low oil uplift for high water cut wells
  • Didn’t result in any change in production or slugging on low water cut wells

• No well integrity or performance of topside process systems issues were observed during either trial as determined in the pretrial assessment

• Plan is to test technology on all gas lifted wells in order to quantify production uplift & define number of wells which will be included in business case for permanent implementation
Questions?