Evaluation of Corrosivity of Produced Fluids during SAGD Operations

OLI Simulation Conference 2014

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Problem Definition

- Heavy oil extraction using SAGD for several decades in oil sands
  - No severe acid gas corrosion despite 35-40 mol. % CO₂, 2-3 mol. % H₂S
  - Lack of observed corrosion does not align with conventional wisdom
  - High operating temperatures (>150°C), wetting of steel surface by bitumen, high produced water pH, favorable H₂S/CO₂ ratio may be forming a protective, dense, and stable layer of corrosion products

- Physico-chemical modeling done to obtain pH profiles, carbon steel corrosion rates – Results validated through electrochemical testing
Assumptions for Modeling

- Corrosion likelihood of SAGD produced fluids estimated by assessing thermodynamic equilibrium along the production process (P, T)
  - Separate simulations for topside and downhole (pH and corrosion rate)
  - Validated for topside using lab testing (CR) and field data (pH)
  - Produced gas compositions, fluid rates from inlet separator
  - For downhole simulations, linear T-P profile considered

- Extracted heavy oil composition is complex; pseudo composition based on alkenes was assumed (carbon number 28)

<table>
<thead>
<tr>
<th>Component</th>
<th>Fraction (mol/mol)</th>
</tr>
</thead>
<tbody>
<tr>
<td>n-Eicosane</td>
<td>0.1</td>
</tr>
<tr>
<td>Docosane</td>
<td>0.1</td>
</tr>
<tr>
<td>Tricontane</td>
<td>0.25</td>
</tr>
<tr>
<td>n-Dotriacontane</td>
<td>0.3</td>
</tr>
<tr>
<td>Tetracontane</td>
<td>0.25</td>
</tr>
</tbody>
</table>
Experimental Design

- Wellhead 170°C, 2000 kPa; Steam chamber 250°C, 4050 kPa
- High temperature, high pressure electrochemical tests to study effect of oil phase and temperature – 1800 kPa, room temp. to 150°C
- AISI 1010 steel (WE), Ag/Ag$_2$S electrode (RE), UNS N06200 alloy (CE)
- Synthetic SAGD produced brine (produced water PW)

<table>
<thead>
<tr>
<th>Compound</th>
<th>Amount (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CaCl$_2$</td>
<td>45</td>
</tr>
<tr>
<td>NaCl</td>
<td>1021</td>
</tr>
<tr>
<td>MgCl$_2$</td>
<td>24</td>
</tr>
<tr>
<td>Na$_2$CO$_3$</td>
<td>100</td>
</tr>
<tr>
<td>KCl</td>
<td>50</td>
</tr>
<tr>
<td>NaHCO$_3$</td>
<td>220</td>
</tr>
<tr>
<td>FeSO$_4$</td>
<td>10</td>
</tr>
</tbody>
</table>

- Bench Top Autoclave (BTA) with 0%, 30%, 50% produced bitumen
- BTAs charged with gas mixture (4 mol. % H$_2$S, 40 mol. % CO$_2$, bal. N$_2$)
Effect of Temperature and Oil Phase on PW pH (topside)

- pH increase with temperature due to reduced solubility of acid gases in the aqueous phase and desorption from the oil phase
- As oil fraction increases, produced water pH increases
  - Partitioning of CO₂ and H₂S to oil phase
Effect of Temperature and Oil Phase on Corrosion Rate (topside)

Threshold CR value observed
- Availability of CO₂/H₂S
- Reduced acid gas (partitioning and desorption) lowers CRs

CR decreases as oil fraction in PW increases
- Inhibitive bitumen, protective oxides
Effect of Temperature and Oil Phase on OCP (topside)

Reduced availability of CO₂ and H₂S due to desorption from PW shifts E_{OCP} values towards more noble directions

- Potential displacement increases once threshold temperature is reached
Cathodic current density increased, anodic branch reduced (T-effect)
  • Thermal activation, protective Fe$_3$O$_4$/Fe$_2$O$_3$ layer formation

Cathodic current density reduced, noble corrosion potentials (Oil effect)
  • Partitioning of acid gases towards the oil phase
Cathodic current density increased, anodic branch reduced (T-effect)
- Thermal activation, protective Fe$_3$O$_4$/Fe$_2$O$_3$ layer formation

Cathodic current density reduced, noble corrosion potentials (Oil effect)
- Partitioning of acid gases towards the oil phase
Effect of Temperature and Oil Phase on Polarization (topside)

- Cathodic current density increased, anodic branch reduced (T-effect)
  - Thermal activation, protective $\text{Fe}_3\text{O}_4/\text{Fe}_2\text{O}_3$ layer formation
- Cathodic current density reduced, noble corrosion potentials (Oil effect)
  - Partitioning of acid gases towards the oil phase
Stability of passive film (Fe$_3$O$_4$/Fe$_2$O$_3$ layers) on steel surface inferred from thermodynamic stability diagrams of possible solid species.
Effect of Temperature and Oil Phase on PW pH (downhole)

- pH increases along pressure-temperature profile of producing well
  - From the top (170°C) to the downhole (250°C)
- pH increases with increasing oil fraction as well
  - Partitioning of acid gases towards the oil phase
Threshold CR value observed as in the case of topsides

- Limited availability of acid gas (partitioning and desorption) lowers CRs

CR decreases as oil fraction in PW increases

- Inhibitive bitumen, protective oxides

Overall CRs less than 0.035 mm/y (1.4 mpy)
Effect of Temperature and Oil Phase on OCP (downhole)

Reduced availability of CO$_2$ and H$_2$S due to desorption from PW shifts $E_{OCP}$ values towards more noble directions
**Estimated Service Life Using Attrition Rate Modeling (topside)**

- Survival probabilities decrease up to threshold temperature (130°C)
  - At temperatures below 73°C or above 130°C, service life is beyond 50 years
- Presence of oil phase results in an extended service life with no appreciable risk of failure up to and beyond 50 years of service
Conclusions

- Produced water pH increases with temperature and oil content in produced fluids; oil content effect is greater than temperature effect.
- Corrosion rate simulations validated by lab tests performed under topside conditions; peak corrosion rate observed followed by drop-off.
- Corrosion rates are dependent on temperature and oil phase fraction; corrosion decreases most likely due to inhibitive nature of bitumen and formation of protective oxide films ($\text{Fe}_2\text{O}_3$/Fe$_3$O$_4$).
- At downhole, C-Mn steel has negligible corrosion rates due to protective films; other forms of localized attack possible per literature.
- Passive film formation is due to effect of temperature and oil content in reducing CO$_2$ and H$_2$S activities in the produced water.
- Attrition rate modeling indicates that likelihood of failure increases at the surface conditions when temperature is between 90°C to 130°C.
THANK YOU FOR THE ATTENTION!

QUESTIONS?