EOR - Introduction

Arne Skauge
Centre for Integrated Petroleum Research

EOR fundamentals and toolbox
Structure of presentation

EOR basics

EOR experience North Sea reservoirs

Gas injection EOR

Waterflood EOR

Way forward
EOR basics
Recovery Mechanisms (conventional view)

Primary Recovery
- Natural Flow
- Artificial Lift
  - Pump
  - Gas Lift
  - Etc.

Secondary Recovery
- Waterflood
- Pressure Maintenance
  - Water
  - Gas Reinjection

Tertiary Recovery
- Thermal
- Chemical
  - Solvent
  - Other

Conventional Recovery

Enhanced Recovery

Source: Adapted from the Oil & Gas Journal, Apr. 23, 1990

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Target Oil for EOR

Some definitions:

- **Primary oil recovery** is where the wells in a reservoir produce under the natural reservoir energy (pressure)
  - typical oil recovery from 1-10% of oil in place

- **Secondary oil recovery** is where we inject water (nearly always) to displace the oil = waterflooding; same effect if strong aquifer drive
  - typical oil recovery from 15-60% of oil in place

- **Improved or Enhanced oil recovery** (EOR; IOR) is where we do something more advanced to obtain the oil left in the reservoir after secondary recovery
Oil recovery efficiency = $E_D \times E_A \times E_V$

$E_D$  

$E_A \times E_V$

Untswept area

$\text{Sor} = \frac{1}{Bo} \cdot V_p \cdot (S_{oi} - S_{or}) \cdot EA \cdot EV$

$S_{oi} = 1 - S_{wi}$

Saturation, $S$

$V_p$

Porevolum, $V_p$

0 1

0 1

0 1

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Oil recovery efficiency = $E_D \times E_A \times E_V$

$N_p = \left[ \frac{1}{B_o} \cdot V_p \cdot (S_{oi} - S_{or}) \right] \cdot E_A \cdot E_V$
Trapped (residual) oil & Bypassed Oil: the targets for EOR

Inject water

Trapped Oil (10 - 30%)

Bypassed Oil (20 - 60%)

Produce oil + Water

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Trapped Oil at the Pore Scale in a Rock

Residual oil saturation

This is the capillary trapped oil or residual oil, $S_{or}$

... consider the mechanism of trapping

N.B. lengthscales Particulary ...

Rock grains (~10 - 100µm)

Rock pores (~0.1 - 100µm)

trapped oil “ganglia” (or blobs)

Rock pores ~0.1 - 100µm
Residual oil saturation

Trapped Oil at the Pore Scale in a Rock: trapping by “snap-off”

This oil filament is unstable and “snaps”

Oil escapes through continuous oil phase

OIL TRAPPING BY FILAMENT SNAP OFF

CIPR – CENTRE FOR INTEGRATED PETROLEUM RESEARCH
Residual oil saturation

Trapped Oil at the Pore Scale in a Rock: trapping by “snap-off”

Oil escapes through continuous oil phase
Trapped Oil at the Pore Scale in a Rock:
pressure to mobilise oil into a smaller pore

Residual oil saturation

SO WHAT CAN WE CHANGE TO MOVE RESIDUAL OIL ??

\[
\frac{\Delta P}{\Delta x} = \frac{2 \sigma}{\Delta x} \left( \frac{1}{R_2} - \frac{1}{R_1} \right)
\]

Pressure gradient to mobilise oil

Oil pressure = \( P_{o2} \)

Water pressure = \( P_w \)
Trapped Oil at the Pore Scale in a Rock: pressure to mobilise oil into a smaller pore

SO WHAT CAN WE CHANGE TO MOVE RESIDUAL OIL ??

\[
\frac{\Delta P}{\Delta x} = 2\sigma \left[ \frac{1}{R_2} - \frac{1}{R_1} \right]
\]

Possibly LOWER interfacial tension, \( \sigma \), but HOW ??

- Surfactant - “soaps” lower \( \sigma \)

- Inject gas (\( CH_4 \), \( CO_2 \) etc..) which can lower \( \sigma \) and do other things
Trapped Oil at the Pore Scale in a Rock: pressure to mobilise oil into a smaller pore

SO WHAT CAN WE CHANGE TO MOVE RESIDUAL OIL ??

\[ \frac{\Delta P}{\Delta x} = 2 \frac{\sigma}{R_2} \left( \frac{1}{R_1} - \frac{1}{R_2} \right) \]

Pressure \textit{gradient} to mobilise oil

Oil pressure = \( P_{o2} \)

Water pressure = \( P_w \)

LOWER interfacial tension, \( \sigma \), but BY HOW MUCH ??

Define Capillary Number, \( N_c \), as 
\[ N_c = \frac{\nu \mu}{\sigma} \]

(\( \nu = \) velocity; \( \mu = \) viscosity; \( \sigma = \) interfacial tension)
Residual oil mobilisation at increased Capillary No.

Reduction in $S_o$ or as $N_c$ increases

$N_c = \frac{v \mu}{\sigma}$

Note that $N_c$ increases as $\sigma$ decreases.

(After Morrow & Chatzis)
Sweep

Areal sweep

\[ M = \frac{K'_r w / \mu_w}{K'_r o / \mu_o} \]

\( M < 1 \) stable front

Vertical sweep

Super-homogen

Tunnel

Worst case

Random
**Enhanced Oil Recovery (EOR)**

**Enhanced Oil Recovery process overview**

- **Thermal**
  - Steam
  - In-situ combustion
  - Hot water

- **Chemical**
  - Alkaline/Caustic
  - Polymer and polymer particles
  - Surfactant - polymer

- **Miscible**
  - CO₂
  - Inert gas N₂
  - Miscible hydrocarbon slug
  - Enrich gas
  - High pressure lean gas

**Low salinity water flood**
- Foam
- WAG
- Hybrid processes
EOR experience North Sea reservoirs
Maximizing oil recovery for Norwegian oil and gas fields

**Challenges**

- Identify undrained area
- Well distance
- Well placement
- Logistics
Maximizing oil recovery for Norwegian oil and gas fields

<table>
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# Maximizing oil recovery for Norwegian oil and gas fields

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**Use solved challenges to activate EOR**

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Experience with field implementation of EOR

**Surfactant**
Single Well Tracer Tests  (Gullfaks, Oseberg)
Surfactant Single Well Test (Gullfaks, Oseberg)

**Other SWTT**
Gas Single Well Tracer Test  (implemented on Oseberg)

Low salinity SWTT  
(Heidrun, Snorre)

**Conformance control**  
(Gullfaks, Snorre, ++)

**WAG**  
(many fields)

**Foam and FAWAG**  
(Brage, Oseberg, Snorre, Veslefrikk, ++)
Gas injection EOR
Gas processes

- Miscible gas
- WAG
- Foam
- CO2 (EOR and sequestration)
Multi-contact miscible gas injection

Vaporizing

Condensing

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Viscous fingering
Sandstone

Carbonates
WAG field applications

Average increased recovery : 5-10 % OOIP

Miscible applications : 9.7 %
Immiscible applications : 6.4 %

Gases injected in WAG
Average increased recovery : 5-10 % OOIP

CO₂ applications : 8 %
Hydrocarbon applications : 5 %

Carbonates / Dolomites have higher average recovery than sandstones
Gas based methods, example

STATFJORD RECOMMENDED FUTURE DRAINAGE STRATEGY

BRENT RESERVOIR

WAG injection

Oil production

BRENT EAST FLANK

W&G injection

Oil production

OIL production

STATFJORD RESERVOIR
Gas and water improving vertical sweep

Down-dip injection: Sweeping attic oil with gas
Gas and water improving vertical sweep

Up-dip injection: Sweeping cellar oil with water
Stone - Jenkins

Calculation of extent of the WAG three-phase zone based on two-phase flow only

Statement: Jenkins analytical model underestimates the WAG three-phase zone when compared to three-phase flow simulation results.

\[ \text{BUT } \text{Som (3ph) } \ll \text{ Sor (2 ph)} \]
WAG Model requirement

- **Gas modeling**
  must include gas trapping
gas rel perm must be able to vary with:
- increasing / decreasing gas saturation
- water saturation
- gas trapping history

- **Water modeling**
  water relative permeability must vary with:
- increasing/decreasing water saturation
- gas saturation

- **Oil modeling**
residual oil must be allowed to change with trapped gas
oil relative permeability should be history dependent

WAG Hysteresis model recommended (developed by Larsen and Skauge)
Available in ECLIPSE
Immiscible WAG: mechanism - redistribution

RED - oil
BLUE - water
WHITE/ YELLOW - gas

\[ \sigma_{go} = 15 \text{ mN/m} \]

network model - micromodel

first gas flood

fifth gas flood
WAG modelling

three-phase Pc (go)

Larsen and Skauge, SPEJ
Skauge and Dale, SPE 111435
Example - Extension of three-phase zone

More detailed fluid flow description
Leads to:
Larger three-phase zone  Som << Sor
115% increase in three phase zone, 35% increase in recovery

- Case 1: only 2-phase rel perm
- Case 2: 2-phase rel perm including Pc
- Case 3: 3-phase rel perm hysteresis and gas trapping
- Case 4: 3-phase rel perm hysteresis and gas trapping including Pc
- Case 5: 3-phase rel perm hysteresis and gas trapping including Pc and the effect of Pc on rel perms

Skauge and Dale, SPE 111435
Foam

- Structured two phase, compressible fluid
- Hexagonal foam texture
- Large gas volume dispersed as bubbles in a continuous liquid phase
- Liquid film is stabilized by surfactants to prevent bubble coalescence
Foam Applications

Near the producer:

a) Gas coning.

b) Gas cusping.

c) Gas channelling in fractures

**Foam blocking**

**a gas cone**
## Foam trials North Sea Area

<table>
<thead>
<tr>
<th>Production well treatments</th>
<th>Foam for mobility control</th>
</tr>
</thead>
<tbody>
<tr>
<td>✓ Oseberg</td>
<td>✓ Snorre</td>
</tr>
<tr>
<td>✓ B-27 1994</td>
<td>✓ Central Fault Block</td>
</tr>
<tr>
<td>✓ B-38 1996</td>
<td>✓ (P-25-P18A) 1997/98</td>
</tr>
<tr>
<td>✓ Beryl</td>
<td>✓ Western Fault Block</td>
</tr>
<tr>
<td>✓ Snorre</td>
<td>✓ Brage</td>
</tr>
<tr>
<td>✓ P-18 1996</td>
<td>1998</td>
</tr>
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</table>
Waterflood EOR
Waterflooding EOR

- Low salinity
- Hybrid EOR
- Surfactants (lower IFT)
- Polymer flooding (sweep ++)
- LPS (microscopic diverging)
- Diverging techniques
- MIOR
- and more
Conventional Chemical Methods for Enhanced Oil Recovery

- **Surfactants** to lower the interfacial tension between the oil and water or change the wettability of the rock
- **Water soluble polymers** to increase the viscosity of the water
- **Polymer gels** for blocking or diverting flow
- **Combinations of chemicals and different methods**
**How surfactant floods are applied in the field**

1. Situation after some time of waterflooding; $S_{or}$ and bypassed oil

2. Inject aqueous surfactant solution - mobilise oil - form “oil bank”
How surfactant floods are applied in the field

3. Post-flush with viscous polymer solution for mobility control

4. Later water injection may lead to some fingering through polymer
Surfactant floods - frontal structure of oil bank

Note the profile of the oil saturation in 1D

Inject low \( \mu \) water postflush
Classical Surfactant Enhanced Oil Recovery

- Surfactants have been used to lower the interfacial tension between the oil and water and/or change the wettability of the rock.
- Water soluble polymers to increase the viscosity of the water.
- Alkaline chemicals such as sodium carbonate to react with crude oil and generate surface activity plus increase pH.
- Combinations of chemicals and methods:
  MF - MPF - SF - SPF - LTPF - AF - APF - ASPF  ...............
Conventional Surfactant Polymer (SP) Flooding & Alkali (A) Flooding

- **Surfactant + Cosurfactant (S):** applied to give a low o/w IFT at some optimal salinity; => high Capillary Number => mobilises previously trapped oil – reduces Sor

- **Polymer (P):** viscosifies the injected brine and give mobility control behind the surfactant slug

- **Alkali (A):** high pH alkali solution applied to cause “soap” formation (saponification) with acids in oil – these “soaps” reduce o/w IFT and cause reduced Sor
Alkali (A) Surfactant (S) Polymer (P) Flooding ASP

KEY aspects of ASP flooding SHORT SUMMARY

1. In situ “soap” generation by Alkali + crude oil – natural surfactants

2. Appropriate phase behaviour with Crude/brine/”soap”+Surfactant

3. LOW IFTs with Crude/brine/”soap”+Surfactant – optimal salinity affected by both [Surfactant] and [“Soap”]

4. LOWER surfactant Adsorption at higher pH

5. OTHER Reservoir Chemistry
   - The CARBONATE/ALKALI System
   - ION EXCHANGE with clays – mainly H+/Na+ , Ca^{2+} etc..
   - MINERAL REACTIONS dissolution/precipitation
Surfactant Types

- Anionic surfactants preferred
  - Low adsorption at neutral to high pH on both sandstones and carbonates
  - Can be tailored to a wide range of conditions
  - Widely available at low cost in special cases
  - Sulfates for low temperature applications
  - Sulfonates for high temperature applications
  - Cationics can be used as co-surfactants

- Non-ionic surfactants have not performed as well for EOR as anionic surfactants
I will argue why:

Conventional surfactant flooding never will become a widely used EOR process for North Sea oil reservoirs

**Statement:**

Ultralow interfacial tension is counteracted by poor flow properties and high surfactant loss (retention)

The presentation will give evidence to this statement and indicate a way forward
Some challenges related to field applications

- Finding a suitable surfactant (and polymer)
  - Low cost (polymer and surfactant)
  - Manageable logistics (polymer and surfactant)
  - Good injectivity (polymer)
  - Low adsorption / loss (polymer and surfactant)
  - Optimal phase behaviour at reservoir conditions (surfactant)
    - Salinity
    - Temperature
    - Pressure
Classical Micellar Polymer Flooding

- Optimizing a surfactant flooding process is a compromise between
  - Ultralow IFT
  - Low retention
  - Injectivity (solution properties)
  - Phase viscosity

Is it possible to have good solution properties at conditions where we can achieve ultralow IFT?

Can we achieve low adsorption/retention at conditions where we can achieve ultralow IFT?
Phase behaviour and IFT as functions of salinity

NaCl/wt% vs IFT/(mN/m)

<table>
<thead>
<tr>
<th>NaCl %</th>
<th>0 0,1 0,2 0,3 0,4 0,5 0,6 0,7 0,8 0,9 1,0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase behaviour</td>
<td>II- II- II- II- II- III III III II+ II+ II+</td>
</tr>
<tr>
<td>IFT/(mN/m)</td>
<td>2,18 0,46 0,21 0,075 0,077 0,05 ~0,013 0,0015 ~0,006 0,013 0,023 0,061</td>
</tr>
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Phase behaviour against heptane follows usual trends.
II- phase behaviour gives low IFT near the three-phase region

EOP: excess oil phase
MEP: microemulsion phase
Correlation between solubility, retention and phase behaviour

<table>
<thead>
<tr>
<th>NaCl wt%</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appearance</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>C</td>
<td>P</td>
<td>P</td>
<td>T</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>O</td>
</tr>
<tr>
<td>Activity</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>79</td>
<td>97</td>
<td>100</td>
<td>98</td>
<td>98</td>
<td>11</td>
<td></td>
</tr>
<tr>
<td>Retention (mg/g)</td>
<td>0,14</td>
<td>0,15</td>
<td>0,15</td>
<td>0,15</td>
<td>1,5</td>
<td>1,5</td>
<td>1,5</td>
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*IFT at S* = 6.6

Other use of surfactants for reducing IFT may be more efficient and economical than classical MPF or surfactant flooding

Ultralow IFT, BUT poor solution properties and high retention

Alternative?
Improving Vertical and Areal Sweep Efficiency: by increasing water viscosity using polymers

Comparison of viscosities of three types of polymers in 1.0% NaCl at 74°F

- Xanthan - a biopolymer
- HPAM - hydrolysed poly acrylamide
- HEC - hydroxy ethyl cellulose

Graph showing comparison of viscosities of Xanthan, HPAM, and HEC against polymer concentration (ppm) and solution viscosity (cp).
Daqing Polymer Injection

Lessons Learned:
- Higher initial water cut results in lower incremental gains in recovery (see figure to left)
- The total cost of polymer flooding ($6.60/bbl inc. oil) is actually less than for waterflooding ($7.85/bbl inc. oil) due to decreased water production and increased oil production.
- More heterogeneous reservoir:
  - larger increase in sweep efficiency
  - shorter response time to polymer flooding
  - strongest influence on recovery is connectivity of pay zones
- To obtain higher recovery with polymer flooding:
  - lower producer WHP
  - stimulate producers
  - increase polymer concentration
  - increase polymer molecular weight

Project Description:
- Over 2000 wells now injecting polymer at Daqing
- Typical slug size is 0.6 PV
- Most well patterns are 5-spot
- about 30-50% of injected polymer is produced
- maximum produced polymer conc. is approx. 2/3 of injected
Waterflooding at high adverse mobility ratio

Mohanty et al 2012

Losal – Designer water – Smart water, etc

Fig. 6 Incremental tertiary recovery ($\Delta S_{\text{oil}}$) by low salinity waterflooding: (a) sandstones and (b) carbonates. Average of 17 outcrop sandstones was 3.9%, for 11 reservoir sandstones was 11.1%, and 12.1% for literature data for reservoir cores or well tests. For outcrop carbonates the average was 2.2% compared to 10.0% for reservoir carbonates.

From Morrow et al paper SPE 154209, Tulsa 2012
Low salinity waterflood

The key parameters or factors claimed to explain low salinity mechanisms for sandstones are:

* Multicomponent ion exchange
* Double layer expansion
* Fines migration
* Wettability alteration
* Microscopically diverted flow
* Impact of alkaline flooding
* pH driven wettability change

*Plus about 20 other suggestions in the literature*
Low Salinity Simulation Approach: Eclipse

- **Brine Tracking** option
  - Salinity can modify brine properties
- **Low Salinity** option
  - Two sets of relative permeability and capillary pressure curves
  - $F_1$ and $F_2$ is weighting factor

\[
\begin{align*}
    k_{ri} &= F_1 k_{ri}^L + (1 - F_1) k_{ri}^H \\
    P_{cij} &= F_2 P_{cij}^L + (1 - F_2) P_{cij}^H
\end{align*}
\]
Sensitivity tests on the rel perm $F_1$ - factor

$$k_{ri} = F_1 k_{ri}^L + \left(1 - F_1\right) k_{ri}^H$$
New combination of EOR methods

Low salinity waterflood may give only modest improved oil recovery for many sandstone reservoirs

Cost of reducing water salinity may be a show stopper

Recent research has made a combined low salinity and surfactant flooding a way of boosting oil recovery and improve the economy of this EOR process

Source:
Low Salinity Surfactant Flooding

- Surfactants targets the residual oil by reducing IFT
- Advantages in low salinity environment
  - Combined effect (low salinity effects at low IFT)
  - May reduce re-trapping of mobilized oil
  - Reduced adsorption / retention
  - More low cost surfactants available
UTCHEM Simulations: LS flood → LS surfactant flood

Good simulation match of production data

Skauge, A., Ghorbani, Z., and Delshad, M., Simulation of Combined Low Salinity Brine and Surfactant Flooding, (Sub ID: 9874), the EAGE IOR Symposium 12th – 14th April 2011 in Cambridge, UK.
Surfactants

Advantage of the combined EOR methods

Low salinity reduces surfactant retention

The combined process can mobilize most of the oil in place in lab core flood experiments

Low cost surfactants can be used at these salinities
Extending polymers for high sal og temp

Nano polymer particles for EOR

Polymer for heavy oil recovery

Oil recovery from water and polymer injection

Waterflooding CDG/LPS

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Nano particles mechanisms sweep improvement, but also..

Microscopic diversion

Spherical particles
Typical size 50-100 nm
Pre-generated particles:

1. Less likely to be adsorbed
2. Expect less chromatographic separation

SEM photograph of CDG particles

Scale 2 µm
LPS in core flood
Sandstone reservoir core (fresh core), $K=900$ mD

- Waterflooding: $Q_i=0.1$ cc/min (3.7 PV)
- Waterflooding: $Q_i=1.0$ cc/min (4.0 PV)
- CDG: $Q_i=1.0$ cc/min (13.4 PV)
- Waterflooding: $Q_i=1.0$ cc/min (6.0 PV)
Intra-molecular aggregate is preferred
LPS flooding in a glass model

Experiments show that water after LPS injection is following new pathways and is mobilising bypassed oil

L: 625 mm  W: 100 mm  Gap: 50-100 μm
Waterflooding at adverse mobility ratio

After LPS injection water is contacting Initially bypassed pores

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Way forward

We will see more advanced flood sequences…

- Polymer - new development and possibilities (Yes)
- Low salinity (?)
- Classical surfactant flooding (?)

Hybrid EOR – **YES**

- Low Salinity Surfactant – Low Salinity Polymer even LSASP – Low Salinity Low Tension Gas - Nano particle polymers
- Foam/Polymer – Nano stabilized foam- Low Tension Gas – WAG – Foam Assisted WAG (FAWAG) and more…..
Thank you