Considerations for Chemical Flooding

Malcolm J. Pitts

Wyoming EOR CO$_2$ Conference
Casper, Wyoming
July 15$^{th}$ and 16$^{th}$
WHY EOR?

Significant oil in discovered reservoirs
• Typically ~70% of OOIP remains in reservoir when abandoned

EOR is technical innovation
• Economically unlocks oil that would otherwise not be recovered

EOR is needed to supply current and future oil demand

Cost curve for oil projects to come on stream by 2020

Source: Citi Investment Research and Analysis (Oil in 2012)
Global CEOR potential estimated to be ~750 billion barrels

- Significant potential in all regions of the world
- Chemical EOR accounts for ~2% of the world's EOR production (OGJ EOR Survey, April 2010)
OIL RECOVERY EQUATION

\[ N_p = E_D E_A E_{VI} \cdot OOIP \]

- \( N_p \) – Oil Recovery
- \( E_D \) – Pore to Pore (Unit) Displacement Efficiency
  (Capillary Mechanism – How well does injected fluid move oil)
- \( E_A \) – Areal Displacement Efficiency
  (Mobility Control Mechanism)
- \( E_{VI} \) – Vertical Displacement Efficiency
  (Mobility Control Mechanism, Conformance Technologies)
- \( OOIP \) – Original Oil in Place

Volumetric Sweep Efficiency
PORE TO PORE DISPLACEMENT EFFICIENCY ($E_D$)

$$E_D = \frac{S_{Oi} - S_{Or}}{S_{Oi}}$$

$S_{Oi} \quad -$ Initial Oil Saturation

$S_{Or} \quad -$ Residual Oil Saturation

$S_{Oi} = 0.77$

$S_{Or} = 0.3$

$E_D = 0.61$
AREAL DISPLACEMENT EFFICIENCY ($E_A$)

$$E_A = \frac{\text{area contacted by displacing agent}}{\text{total area}}$$
VERTICAL DISPLACEMENT EFFICIENCY ($E_{VI}$)

$$E_{VI} = \frac{\text{vertical cross sectional area contacted by displacing agent}}{\text{total vertical cross sectional area}}$$

Higher Permeability

Lower Permeability
$E_D = \text{Unit Displacement Efficiency}$
represents the pore to pore displacement efficiency
microscopic displacement efficiency

$E_D \text{ improved by surfactant and alkali}$

$E_V = \text{Volumetric Sweep Efficiency}$
macroscopic displacement efficiency

$E_V \text{ improved by polymer}$
Chemical EOR Produces 10-20% incremental original oil in place

Implemented in Stages
1. ASP stage – mobilizes oil creating an oil bank
2. Polymer stage – pushes oil bank to producer
3. Water stage – final push to finish the project
1. **EOR Screening – Chemical Candidate**
   - Primary and waterflood performance review
   - Geological characterization and numerical simulation with history match
   - Economic analysis

2. **Laboratory Analyses**
   - Define chemical system for injection

3. **Update Analyses**
   - Numerical simulation
   - Economic analysis

4. **Operational Plan**

5. **Facility Design and Construction**

6. **Project Implementation**
   - Pilot
   - Full field

7. **Monitoring Project Performance**
Main Screening objective: Prevent adverse project selection
  • Identify red flags that should stop the project now

Main parts to screening a chemical EOR project

Reservoir Review
  • Reservoir properties
  • Field location and logistics
  • Calculate floodable pore volume

Recovery + Economic Estimation
  • Estimate potential recoveries based on analogous fields
  • Estimate capital investments
  • Estimate economic recoveries
BASIC RESERVOIR SCREENING

1. Good Waterflood Performance (candidate)
2. Permeability > 25 mD
3. Permeability Variation
4. Sufficient Target Oil Saturation
   • Distribution of Oil Saturation
5. Water for Dissolving Chemicals
   • Chemical Analysis
6. Crude Oil Viscosity < 5000 cP
7. Mobility Ratio
8. Temperature < 250°F
9. Impact of Bottom Water Drive
10. Sufficient Injection Capacity
    • 1 PV < 20 yrs (Or additional wells needed)
\[ N_p = E_D E_A E_{VI} \cdot OOIP \]

- \( N_p \) – Oil Recovery
- \( E_D \) – Pore to Pore (Unit) Displacement Efficiency
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- \( OOIP \) – Original Oil in Place
• Capillary Pressure

\[ \Delta P = P_{w1} - P_{w2} = 2\sigma \left[ \frac{1}{r_1} - \frac{1}{r_2} \right] \]

• Viscous Forces (function of Capillary Pressure)

\[ \frac{\Delta P}{L} K \]

\[ N_{ca} = \frac{Viscous \ Forces}{Surface \ Forces} = \frac{\Delta P/L}{K} \]

\[ \sigma \quad \text{IFT} \]
CAPILLARY NUMBER MECHANISM

\[ N_{vc} = \frac{v \mu}{\sigma} = \frac{K k_{rw} \Delta P}{L} = \frac{\phi N_{Le}^2 k_{rw} \psi^2}{2f} \]
ALKALINE AGENTS

Alkaline Agents used in Chemical EOR

- Sodium carbonate (Na$_2$CO$_3$, soda ash)
- Sodium hydroxide (NaOH, caustic soda)
- Potassium hydroxide (KOH, pot ash)
- Sodium metaborate (NaBO$_2$*4H$_2$O)
- Tri-sodium phosphate (Na$_3$PO$_4$)

IFT is mostly dependent on pH and ionic strength
Main Function of Surfactant:
- Reduce interfacial tension

Surfactant:
- “Surface Active Agent”
- Reduces the interfacial tension between oil and water
ALKALI IFT REDUCTION

![Graph showing interfacial tension vs. alkali concentration](image_url)

- **Alkali Concentration (wt%)**
- **Interfacial Tension (mN/m)**

Curves for:
- **NaOH** (solid line)
- **Na₂CO₃** (dashed line)

**Aliki IFT Reduction**

22 API

42 API
ALKALI-SURFACTANT IFT REDUCTION

- Alkali Concentration (wt%)
- Interfacial Tension (mN/m)

- solid - NaOH plus Surfactant
- dashed - Na$_2$CO$_3$+ Surfactant

22 API
42 API
ALKALI AND SURFACTANT

Alkali
- Reduce Interfacial Tension
  - reacts with oil to form surfactants
- Change Chemistry of Rock
  - alters rock chemistry, changing rock wettability to more water wet
  - alters rock chemistry, reducing polymer and surfactant adsorption
- Enhance Utility of Other Chemicals
  - adjusts pH and salinity
  - reduces polymer size allowing entry into small pores
  - protects polymer from divalent cations in the reservoir
  - allows polyacrylamide polymers to flood higher temperature
  - stabilizes polyacrylamide to H₂S catalyzed oxidative degradation
- Acts as a Mild Biocide

Surfactant
- reduces oil-water interfacial tension

Alkali + Surfactant
- synergistic interfacial tension reduction
Oil Recovery Equation

\[ N_p = E_D E_A E_{VI} \cdot OOIP \]

**Need to understand**
- Mobility Ratio
- Fractional Flow

- \( N_p \) – Oil Recovery
- \( E_D \) – Pore to Pore (Unit) Displacement Efficiency
- \( E_A \) – Areal Displacement Efficiency (Mobility Control Mechanism)
- \( E_{VI} \) – Vertical Displacement Efficiency (Mobility Control Mechanism)
- \( OOIP \) – Original Oil in Place

**Volumetric Sweep Efficiency**
Mobility Ratio – Measure of the efficiency by which a fluid can displace oil

$$\text{Mobility Ratio} = \frac{\text{Mobility of displacing phase}}{\text{Mobility of displaced phase}}$$

$$\text{Mobility Ratio} = \frac{K_{rw} / \mu_w}{K_{ro} / \mu_o}$$

Evaluate $k_{rw}$ at conditions behind front

Always evaluate $k_{ro}$ at conditions ahead of front

$Kr$ based on different saturations
**Unfavorable Mobility Ratio > 1**

Injector

Water

Oil

Producer

---

**Favorable Mobility Ratio < 1**

Injector

Water

Oil

Producer

---

OIL DISPLACEMENT IN 5-SPOT
Fractional flow of water (Fw):

- The flow rate of water divided by the total flow rate
- A function of \(k_{rw}, k_{ro}, \mu_w, \mu_o, \gamma_w, \gamma_o\) and dip

\[
Fw = \frac{1}{1 + \frac{\mu_{water} \times k_{oil}}{\mu_{oil} \times k_{water}}}
\]

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<td>0.625</td>
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\(Kr\) based on same saturations
**Mobility Ratio**

\[
\text{Mobility Ratio} = \frac{K_{rw} \times \mu_o}{K_{ro} \times \mu_w}
\]

**Waterflood volumes for 3 MR's**

\[
f_w = \frac{1}{1 + \frac{\mu_{water} \times k_{oil}}{\mu_{oil} \times k_{water}}}
\]

**Different Path to same E_D**
OIL RECOVERY EQUATION

\[ N_p = E_D E_A E_{VI} \cdot OOIP \]

Need to understand
• Reservoir Characteristics

\( N_p \) – Oil Recovery
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  (Mobility Control Mechanism, Conformance Technologies)
\( OOIP \) – Original Oil in Place
Application of conformance polymer gels is case specific and not applicable for all fields

- Gels – Used to Divert or Eliminate Flow
- simple fracture problems
- fracture network conformance problems
- matrix conformance problems without cross flow
- matrix conformance problems with cross flow
- Key objectives:
  - Target vertical sweep efficiency
  - Selective injection
  - Plug problem zones
Laboratory Program is Process Dependant

- **Economic Oil**
- **No incremental recovery**
- **Incompatibility**
- **Unstable**

**Phase 1** **Phase 2** **Phase 3**

**DEVELOPING CHEMICAL FORMULATION**
Laboratory Evaluation to Prove Concept using Reservoir Fluids and Core

Gel Development in Appropriate Water
What is Reservoir Simulation?

• A numerical model of the reservoir
  - Correct physics of fluid flow
  - Allows for heterogeneous property distribution
  - Combination of several methods of analysis
    ▪ Geology Model
    ▪ Material Balance
    ▪ Fluid Flow Mechanics/Performance

• Allows forecasts/sensitivity analysis of reservoir performance
  - Reservoir management
  - Process design
  - Strategic development planning
  - Testing of alternative development options
  - Recovery prediction
  - Testing of uncertain reservoir parameter
4 STAGES OF CHEMICAL EOR SIMULATION

1. Geologic/Reservoir Understanding
   - Geo-model
   - Well Logs
   - Seismic
   - Core Studies
   - Fluid Analysis
   - Flow Characteristics
   - Well Data
   - PTA
   - Etc...

2. History Matching I – Field Performance

3. History Matching II – Lab/Coreflood Performance

4. Forecasting & Scenario Analyses
General Reservoir location identifies:
• Approximate transportation costs
• Facility size constraints
• Additional potential concerns

Laboratory studies identify:
• Water treatment requirements
• Actual chemicals needed
• Chemical costs per volume of each chemical

Simulation (or through other reservoir evaluation methods) identify:
• Approximate volume of chemicals needed
• Production profile for chemical flood profile
• Approximate size of facility needed
• Additional well activity (work over/new drill/conversions)

Objective of Chemical Floods
• Maximize NPV of the project
• Increase Reserves
CEOR Economics are better earlier in the life of the project

• Too early is subject to additional risk
  - Establish injection/communication between wells

*If volume of $A + B = A + C$, Which option is preferred? better economics?*
Timing of Minnelusa Chemical Floods

- Cambridge – Secondary flood $2.95 / bbl
- Tanner – Waterflood to 40% oil cut $4.49 / bbl
- Mellott Ranch – 35 year waterflood to 5% oil cut $19.06* / bbl

* premature stoppage of chemical injection
Field implementation is a process and depends on successful completion of previous steps

**SCREENING**
- Reservoir Selection and Optimization

**DESIGN**
- Laboratory Design
- Numerical Simulation, Economics and Field Design
- Facilities Design

**IMPLEMENT**
- Facilities Construction Oversight
- Operations Planning and Quality Control
- Monitoring Project Performance
Purpose

- Prepare water for chemical EOR
- Insure alkali, surfactant, and polymer are mixed according to design specifications
- Insure solution has correct physical characteristics
• Polymer Slicing Unit - polymer mixing

• Strong Acid ion exchange water softening

• Oil removal from water
  ▪ Induced gas flotation – field gas
  ▪ Walnut shell filter polishing

• Polymer mother solution mixed with surfactant solution
  ▪ Static mixer

• Alkali mixed with surfactant-polymer
  ▪ Static mixer
  ▪ 25 micron filtration
Instow: Saskatchewan, Canada

ASP area = 50,000 MBBL PV
Mobility Ratio = 6
Permeability = 200 md
Temperature 120°F
Oil API Gravity = 22°
Oil Viscosity = 24 cp

Water beginning August 1959
Alkaline-Surfactant-Polymer flooding beginning October 2007
0.50 wt% NaOH plus 0.07 wt% ORS-43F plus 1200 mg/l Flopaam 3230S

\[ N_P = E_D \times E_V \times OOIP \]
Highlight of screening:

- Favorable conditions for chemical EOR
- Excellent analogue fields with lab studies (Dollard) and field application (Rapdan)
- Skip small scale pilot

<table>
<thead>
<tr>
<th>ASP Screening Guide</th>
<th>Recommended</th>
<th>Dollard</th>
<th>Instow</th>
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<tr>
<td>Property</td>
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<tr>
<td>Oil Gravity (API)</td>
<td>&gt;20</td>
<td>22</td>
<td>22</td>
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<tr>
<td>Oil Viscosity (cP)</td>
<td>&lt;35</td>
<td>9 (20.5 dead)</td>
<td>11 (24.1 dead)</td>
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<tr>
<td>Reservoir Permeability (mD)</td>
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**INSTOW – LABORATORY DESIGN**

**List of chemicals tested**

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<tr>
<th>Chemical Name</th>
<th>Structure</th>
<th>Chemical Type</th>
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<td>Na2CO3</td>
<td>Sodium Carbonate</td>
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<tr>
<td>NaOH</td>
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<td>Floquat 3630N</td>
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**Normalized oil recovery comparison of radial corefloods**

![Normalized oil recovery comparison](image_url)
Calibrated model used to identify:
• Infill wells
• Conversion wells
• Production profile
• Incremental production
LABORATORY
MONITORING PERFORMANCE
Instow 50,000,000 bbl Pilot, Phase 1

Oil cut increase from 3% to 11%
Oil rate increase 136%
Oil cut increase from 3.3% to 50%
Oil rate increase 1,029%

Oil cut increase from 2.7% to 32%
Oil rate increase 676%

Oil cut increase from 1.7% to 40%
Oil rate increase 600%
INSTOW – SIMULATION COMPARISON

ASP Phase 1 Production vs Forecast

Updated Forecast - Jan 2010
Weekly Average
Original Decline - 2007

1110 bbl/d (176.4m3/d)
incremental average

bbld Incremental oil

SPE 155541
**Injection**
- Injectivity loss due permeability reduction, solution viscosity
  - Approximately a 40% loss of injectivity
- NaOH pump corrosion
- Injection distribution system
  - Alkali destroyed anhydride expoy
  - Replace injection distribution system

**Production**
- No scale production
  - Monitor produced fluids pH
- Polymer production
  - Adsorption on fire tubes
  - Water spray on fire tubes
  - Replace fire tubes
  - Gas flotation essentially useless
- Shear pump used to reduce viscosity of produced polymer solution
- SAC softener – issues working as the water TDS increased from flood
What happened?
WARNER – ASP FLOOD ISSUES

Injection

• Injectivity loss due to scale formation, reduced produced water, facilities issues related to scale production
  ▪ Approximately a 25% loss of injectivity

Production

• Polymer adsorption on fire tubes – reduced life
  ▪ Water spray bars
  ▪ Replace fire tubes
• Breakable emulsion with production chemicals
• Shear pump used to reduce viscosity of produced polymer solution
• Pressure build up in areas of field from changes inj/pro ratios
• Silicate scale production
  ▪ Attempt to solve with chemicals, reasonable success
    o Chemical inhibitors varied with flood progression
      – 12 inhibitors
  ▪ Loss of productivity
  ▪ Re-drill some wells
  ▪ Monitor flood production (monthly basis)
    o pH, produced water analysis, well head steel coupon
  ▪ Pipeline pigging program
Minnelusa Formation: Wyoming, USA

Timing of Minnelusa Chemical Floods

- Cambridge – Secondary flood
- Tanner – Waterflood to 40% oil cut
- Mellott Ranch – 35 year waterflood to 5% oil cut

\[ N_P = E_D \times E_V \times OOIP \]

\[ N_P = E_D \times [E_V] \times OOIP \]
Cambridge: Wyoming, USA

ASP area = 5,684 MBBL
PV

Mobility Ratio = 2.2 to 5.8

Permeability = 845 md

Oil API Gravity = 20°
Oil Viscosity = 31 cp

ASP Flood began 1993

\[ N_P = E_D \times E_V \times \text{OOIP} \]
CAMBRIDGE ASP INJECTION PLANT

- Sodium Carbonate Storage ($\text{Na}_2\text{CO}_3\text{ Storage}$)
- Surfactant Storage
- Alkali and Surfactant mixing and filtration
- Polymer Storage and Mixing
CAMBRIDGE FIELD: ASP

Cambridge Alkaline-Surfactant-Polymer Injection Plant (1,500 bbl/day plant)
Ultimate Oil Recovery
Primary and Waterflood
ASP Incremental Recovery
Cost per Incremental Barrel
Cost includes chemicals and plant

73.2 % OOIP
39.8 % OOIP
33.4 % OOIP
2.95 $/bbl
Implementation must be complemented by constant performance monitoring to obtain the desired results.

Polymer Production – Oil Cut Mobility Control

- Good mobility control suggested by produced polymer coincident with oil bank
- Carbonate production indicator of neutralization of NaOH injected, calibration of adsorption isotherm in model
- No Ca production, little scale potential

Cambridge Ion and Chemical Production

- Polymer increases coincident with decline in Ca and Mg good mobility control
- Carbonate increases behind polymer suggesting chromatographic separation
TANNER – ASP FLOOD

ASP area = 2,528 MBBL PV

Mobility Ratio = 3.2

Permeability = 200 md

Temperature 175°F

Oil API Gravity = 21°

Oil Viscosity = 11 cp

Waterflood beginning November 1997

Alkaline-Surfactant-Polymer flooding beginning March 2000

\[ N_P = E_D \times E_V \times \text{OOIP} \]
Ultimate Oil Recovery
Primary and Waterflood to 3/2000 – 40% oil cut
Primary and Waterflood to 3% oil cut
ASP Incremental Recovery

65.0 %OOIP
31.3 %OOIP
48.0 %OOIP
17.0 %OOIP

Cost per Incremental Barrel $4.49 (estimated)
Includes Chemical and Facilities
MELLOTT RANCH – ASP FLOOD

Mellott Ranch: Wyoming, USA

ASP area = 12,200 MBBL PV

Mobility Ratio = 7.6

Permeability = 640 md

Temperature 133°F

Oil API Gravity = 21°

Oil Viscosity = 23 cp

Waterflood beginning December 1965

Alkaline-Surfactant-Polymer flooding beginning August 2000

\[ N_p = E_D \times E_v \times OOIP \]
Mellott Ranch Northeast Sand, Northern Wells

34-02, 41-11, and 11-12H Producing
21-11 and 32-1 Injecting

- Oil Cut
- Oil
- Water
- Polymer Injection

ASP Injection Starts August 2000
Polymer Injection Starts June 2004
Water Flush Starts April 2006
RAPDAN – POLYMER FLOOD

N_P = E_D × E_V × OOIP

Rapdan: Saskatchewan, Canada

Formation: Upper Shaunavon
Depth: 4,590 ft
Temperature: 131°F
Pore volume: 28,688 Mbbl
Original Oil in Place: 18,590 MSTB
Thickness: 30 ft
Average Porosity: 18%
Average Permeability: 116 md
Reservoir Water Salinity: 6,000 mg/L
Oil API Gravity: 23°
Oil Viscosity: 10 cp
Water Viscosity: 0.52 cp
Mobility Ratio: 4.5
RAPDAN POLYMER STORAGE AND MIXING
Pore volume 28,688 Mbbl
Original oil in place 18,590 MSTB

Est. primary and waterflood recovery 31.3% OOIP
Est. Ultimate total oil recovery 46.2% OOIP
Polymer flood incremental oil recovery 14.9% OOIP

Final oil saturation 0.349 PV
Chemical cost per incremental barrel of oil $2.05
Formation: Minnelusa B
Depth: 7,350 ft
Temperature: 170°F
Thickness: 7 ft
Pore Volume: 4 MMBBL
Average Permeability: 22 mD
Porosity: 30.7%
Oil API Gravity: 26°
Oil Viscosity: 8.2 cp
Water Viscosity: 0.45 cp
Mobility Ratio: 1.3

**Timetable**
- Primary production: Jan 1976
- Waterflood: Jan 1984
- Water: Nov 1996+

**Injected Solution**
- 1.25 wt% NaOH
- 0.2 wt% active Petrostep B-100

\[ N_p = E_D \times E_V \times OOIP \]
**BIG HORN BASIN – MARCIT POLYMER**

**N_p = E_D \times E_V \times OOIP**

**Big Horn Basin:**
Wyoming, USA

<table>
<thead>
<tr>
<th>Formation</th>
<th>Lithology</th>
<th>Perm(mD)</th>
<th>Thickness(ft)</th>
<th>Temp(°F)</th>
<th>Spacing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Embar/Phosphoria</td>
<td>carbonate</td>
<td>180-350</td>
<td>20-35</td>
<td>105-140</td>
<td>10-20</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Madison</td>
<td>carbonate</td>
<td>150-300</td>
<td>120-190</td>
<td>110</td>
<td>20</td>
</tr>
<tr>
<td>Tensleep</td>
<td>sandstone</td>
<td>30-180</td>
<td>35-85</td>
<td>110-140</td>
<td>10-20</td>
</tr>
</tbody>
</table>

*Brine – 5400 mg/LTDS, 640 mg/L hardness, 100 mg/L H_2S*
<table>
<thead>
<tr>
<th>Treatment Summary</th>
<th>total wells</th>
<th>injection wells</th>
<th>production wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number Treatments</td>
<td>29</td>
<td>17</td>
<td>12</td>
</tr>
<tr>
<td>Incremental Oil (bbls)</td>
<td>3,720,000</td>
<td>3,650,000</td>
<td>63,000</td>
</tr>
<tr>
<td>Ave Incr per Treatment (bbls)</td>
<td>128,000</td>
<td>215,000</td>
<td>5,300</td>
</tr>
<tr>
<td>Ave Cost per Treatment</td>
<td>$44,300</td>
<td>$45,200</td>
<td>$43,100</td>
</tr>
<tr>
<td>Ave Cost per bbl</td>
<td>$0.34</td>
<td>$0.21</td>
<td>$8.21</td>
</tr>
<tr>
<td>% Total Recovery</td>
<td>100</td>
<td>98.3</td>
<td>1.7</td>
</tr>
</tbody>
</table>
Polymer gels can be effective when applied properly.
Observations for Chemical Flood Application

• A chemical flood will not overcome geology.

• If a reservoir can be successfully and efficiently waterflooded, a well designed chemical system can produce an incremental oil volume of 10 to 20% of the original oil in place.

• Chemical processes can be economically applied at any stage in an oil field’s life. Economics are maximized if a project is implemented during its waterflood life.

• Chemical concentrations and slug size are critical. If concentrations are too low, no incremental oil will be recovered. If too high, economics will suffer.
Observations for Chemical Flood Application

- Mobility control essential for a successful chemical flood. If not enough polymer is injected, displaced oil bypassed and is not recovered.

- Injection of a polymer of too high a molecular weight for the reservoir being flooded will reduce the affected reservoir size.

- Reservoir rock is probably the most important factor in the design of a chemical system.

- Low interfacial tensions are required but will not assure success. Many low interfacial tension systems recovered no extra oil in laboratory corefloods and field applications. Chemical systems designed on interfacial tension alone have a high probability of failure in the field.
What Makes A Successful Flood?

- reservoir engineering and geology
- laboratory evaluation
- numerical simulation
- facilities design
- careful field operations
- monitoring flood performance
• Chemical EOR is field proven technology
• Operators must do their homework to be successful
• CEOR is both technologically and economically successful
• Attention to detail in all phases is critical to succeed
• Planning and implementing a CEOR project is time intensive and requires a long term view
• Have a “sponsor”