EOR - Introduction

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EOR fundamentals and toolbox

Structure of presentation

EOR basics

EOR experience North Sea reservoirs

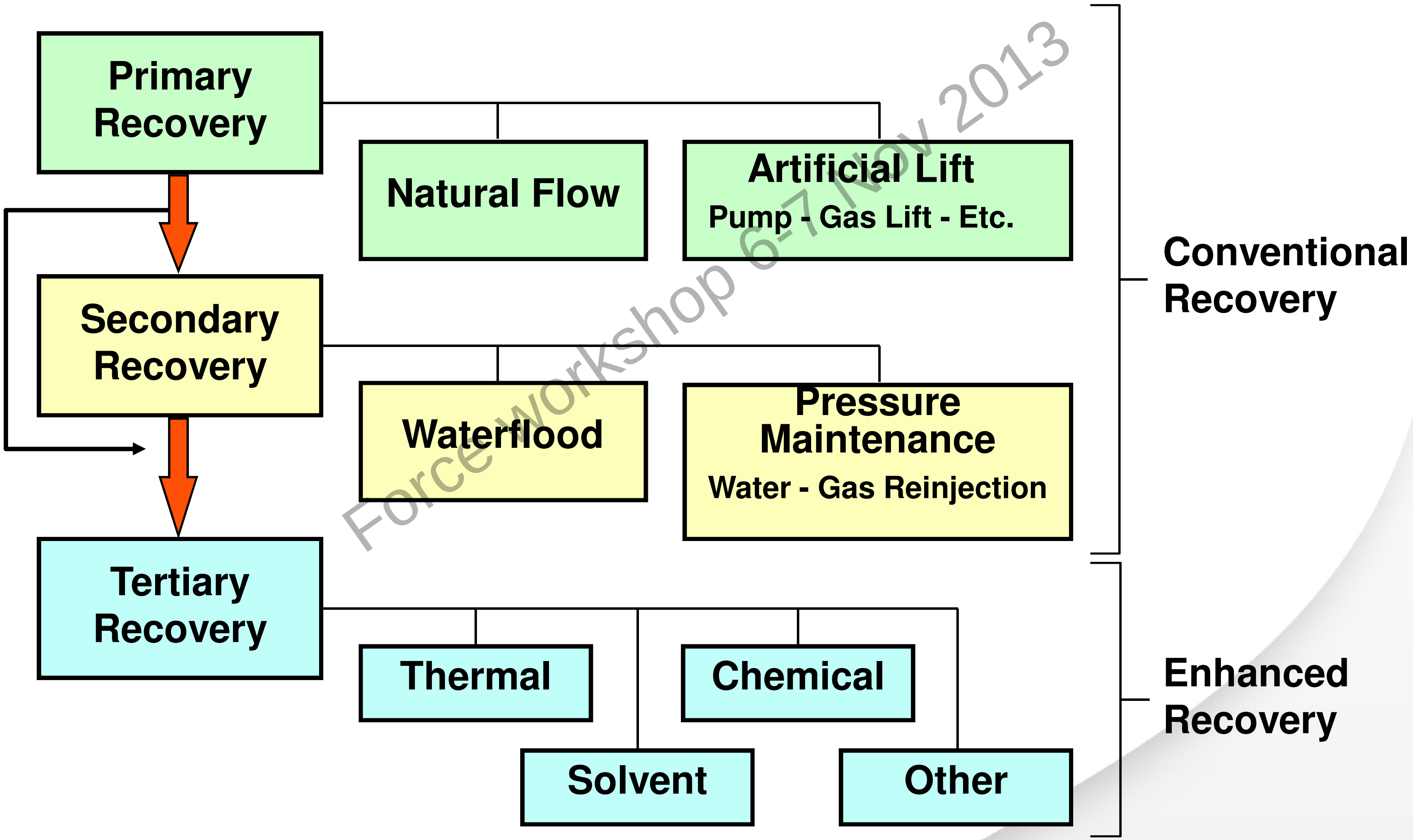
Gas injection EOR

Waterflood EOR

Way forward

EOR basics

Recovery Mechanisms (conventional view)



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

Target Oil for EOR

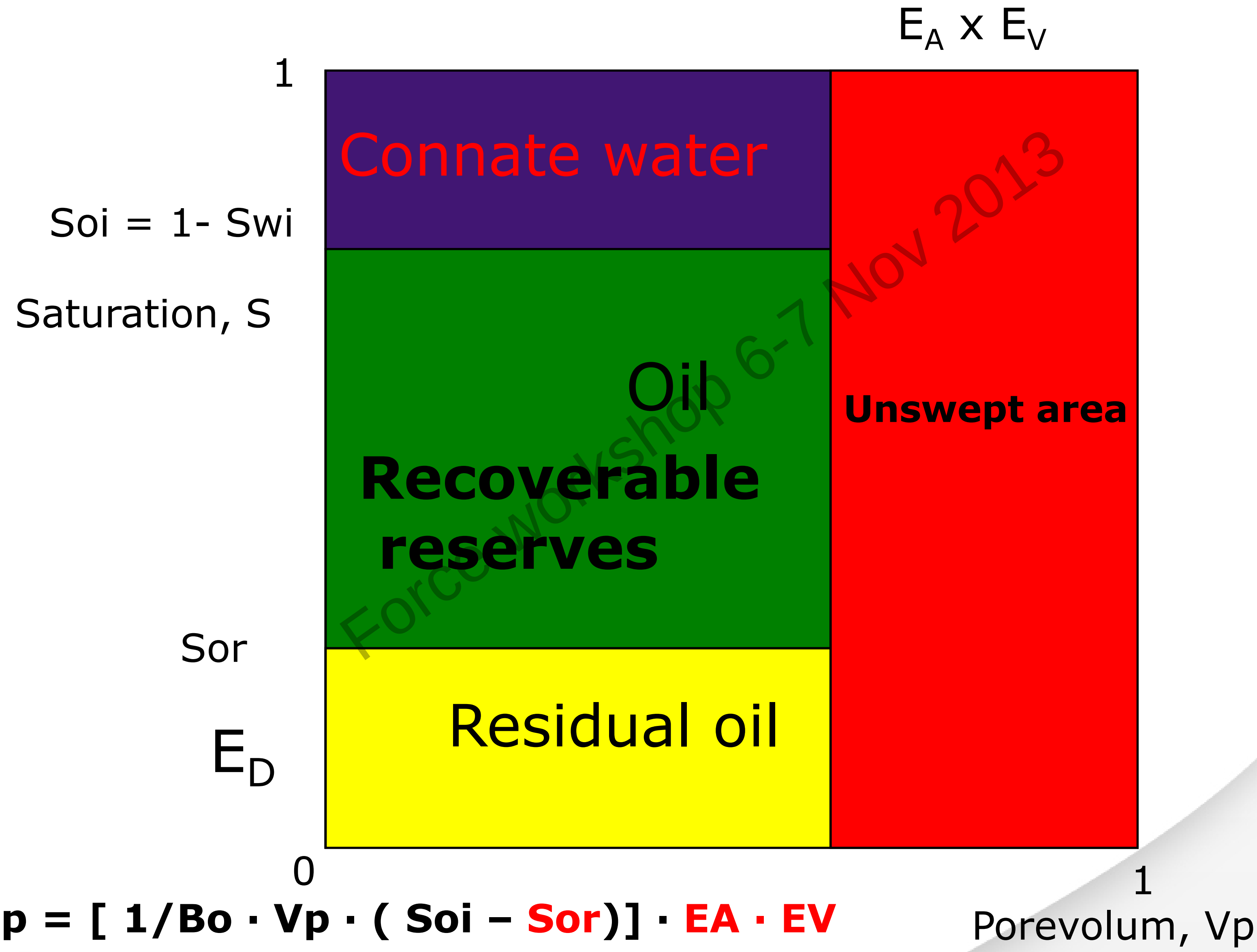
Some definitions:

- **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

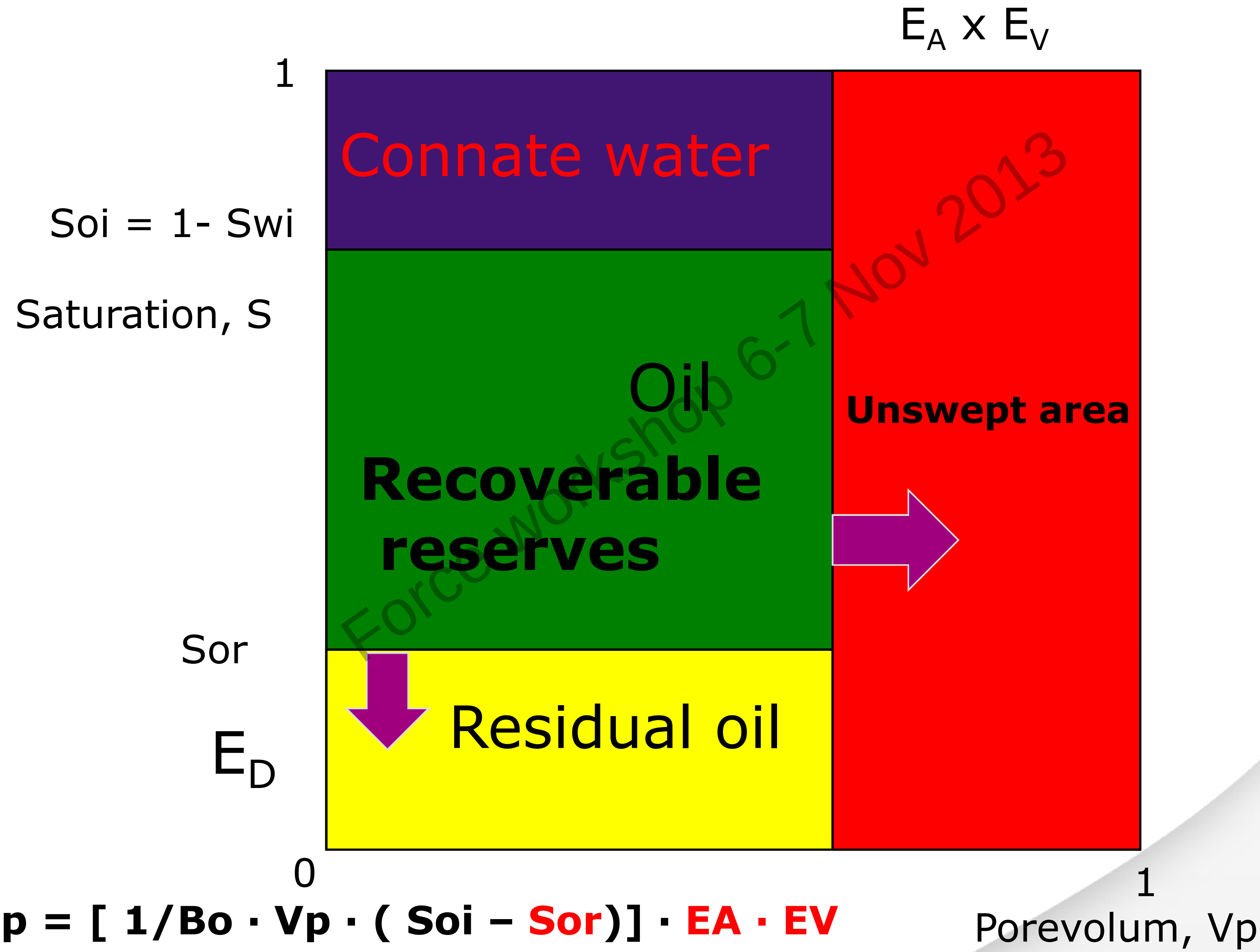
- **Improved or Enhanced oil recovery** (EOR; IOR) is where we do something more advanced to obtain the oil left in the reservoir after secondary recovery

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



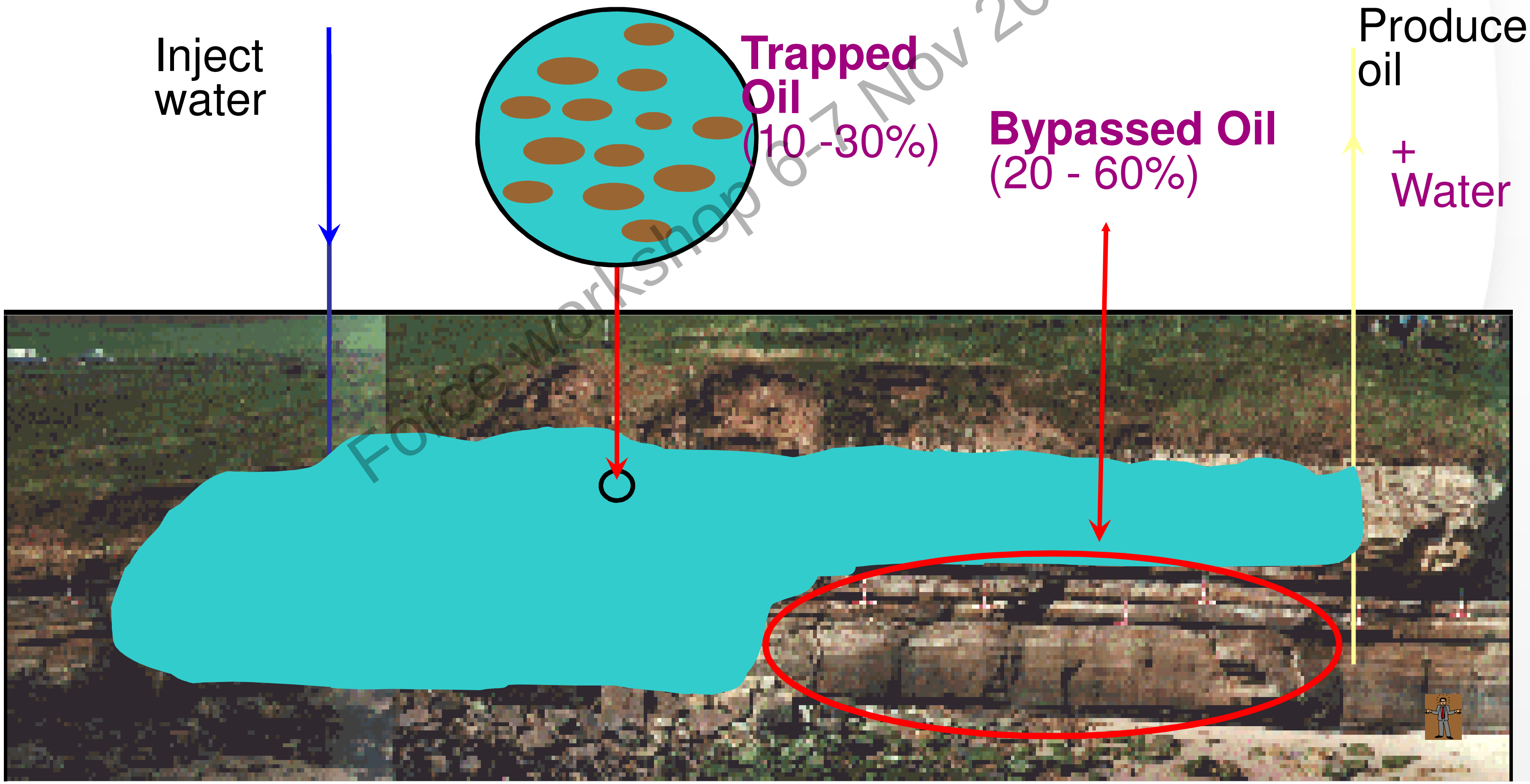
Np = [1/Bo · Vp · (Soi – Sor)] · EA · EV

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



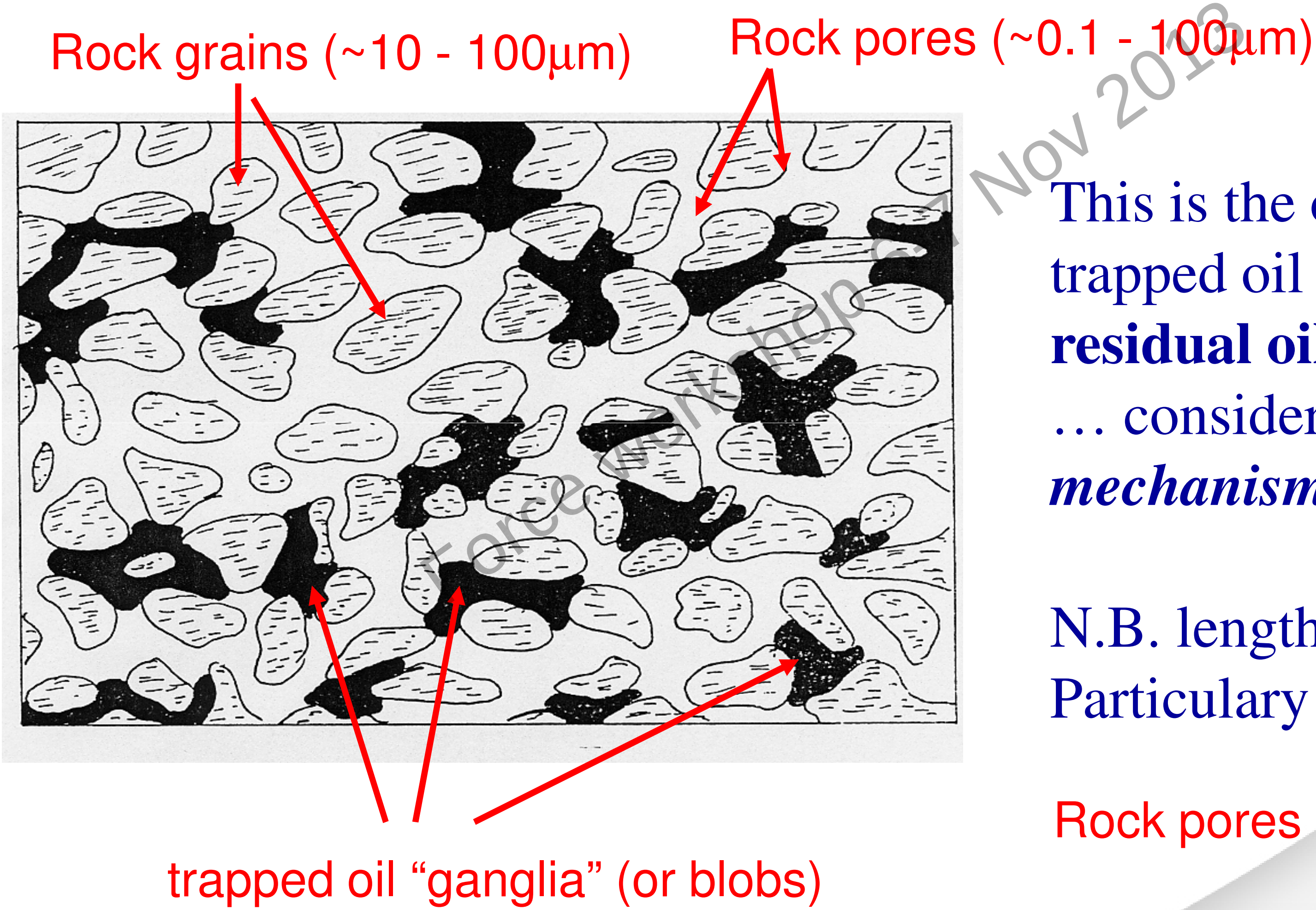
Np = [1/Bo · Vp · (Soi – Sor)] · EA · EV

Trapped (residual) oil & Bypassed Oil:
the targets for EOR



Residual oil saturation

Trapped Oil at the Pore Scale in a Rock



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

… consider the ***mechanism*** of trapping

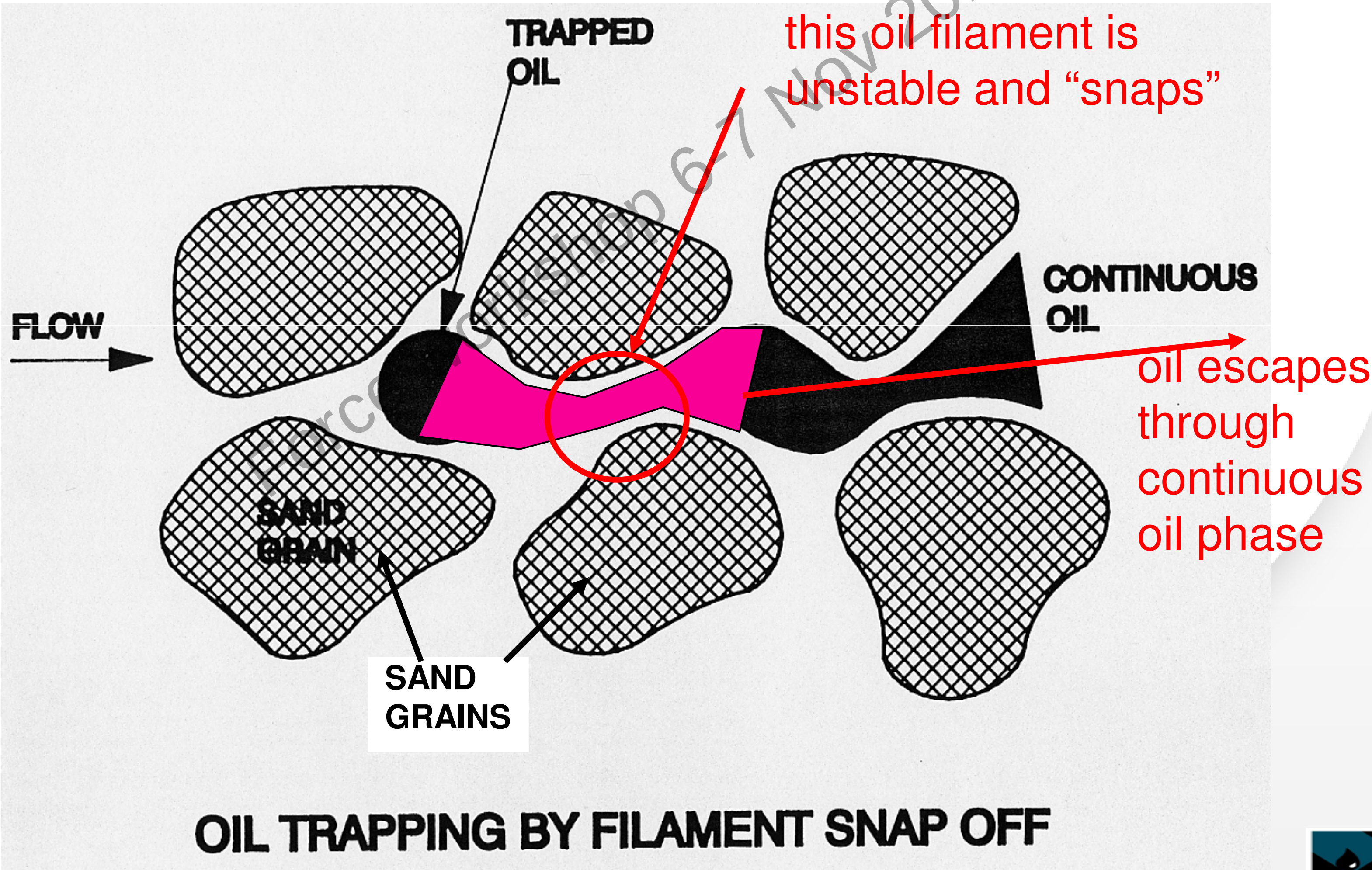
N.B. lengthscales Particulary …

Rock pores ~0.1 - 100μm

Residual oil saturation

Trapped Oil at the Pore Scale in a Rock:

trapping by “snap-off”



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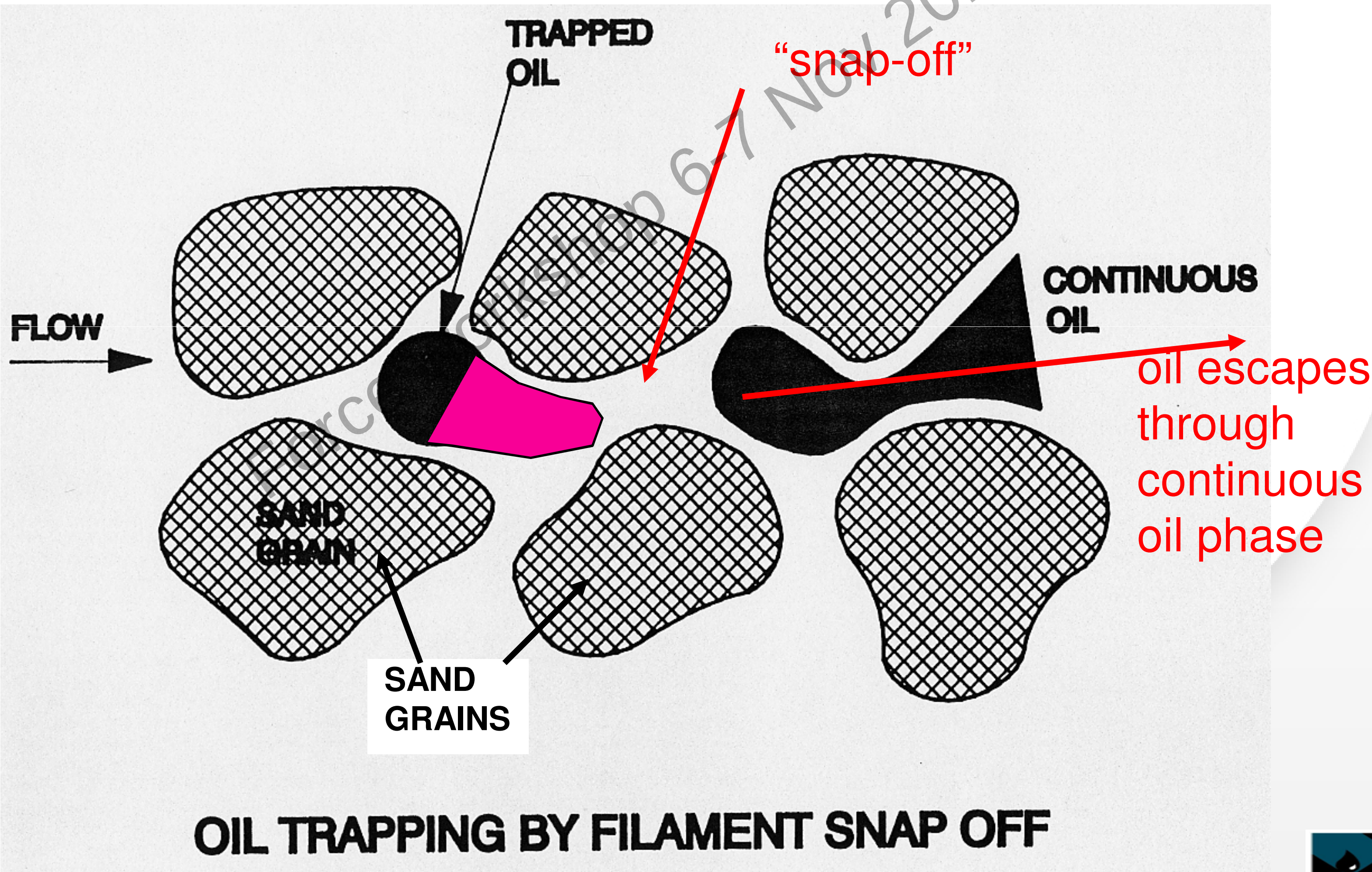
Residual oil saturation

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



Residual oil saturation

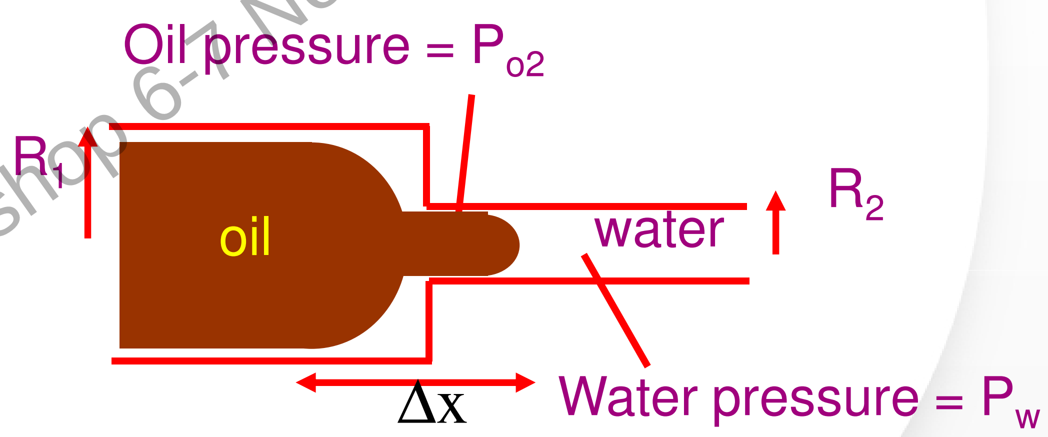
Trapped Oil at the Pore Scale in a Rock:

pressure to mobilise oil into a smaller pore

SO WHAT CAN WE CHANGE TO MOVE RESIDUAL OIL ??

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

Pressure ***gradient*** to mobilise oil



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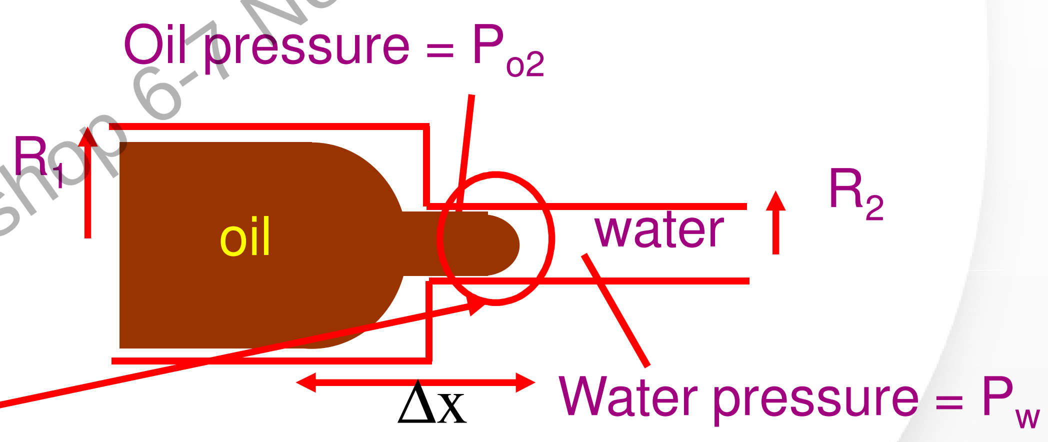

Possibly LOWER interfacial tension, σ, but HOW ??

- Surfactant - "soaps" lower σ

- Inject gas (CH_4, CO_2 etc..) which can lower σ and do other things

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Trapped Oil at the Pore Scale in a Rock:

pressure to mobilise oil into a smaller pore

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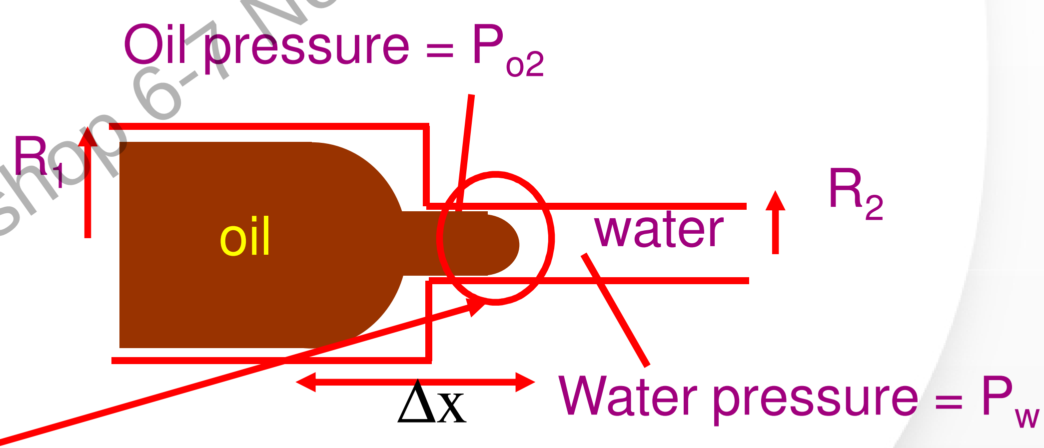
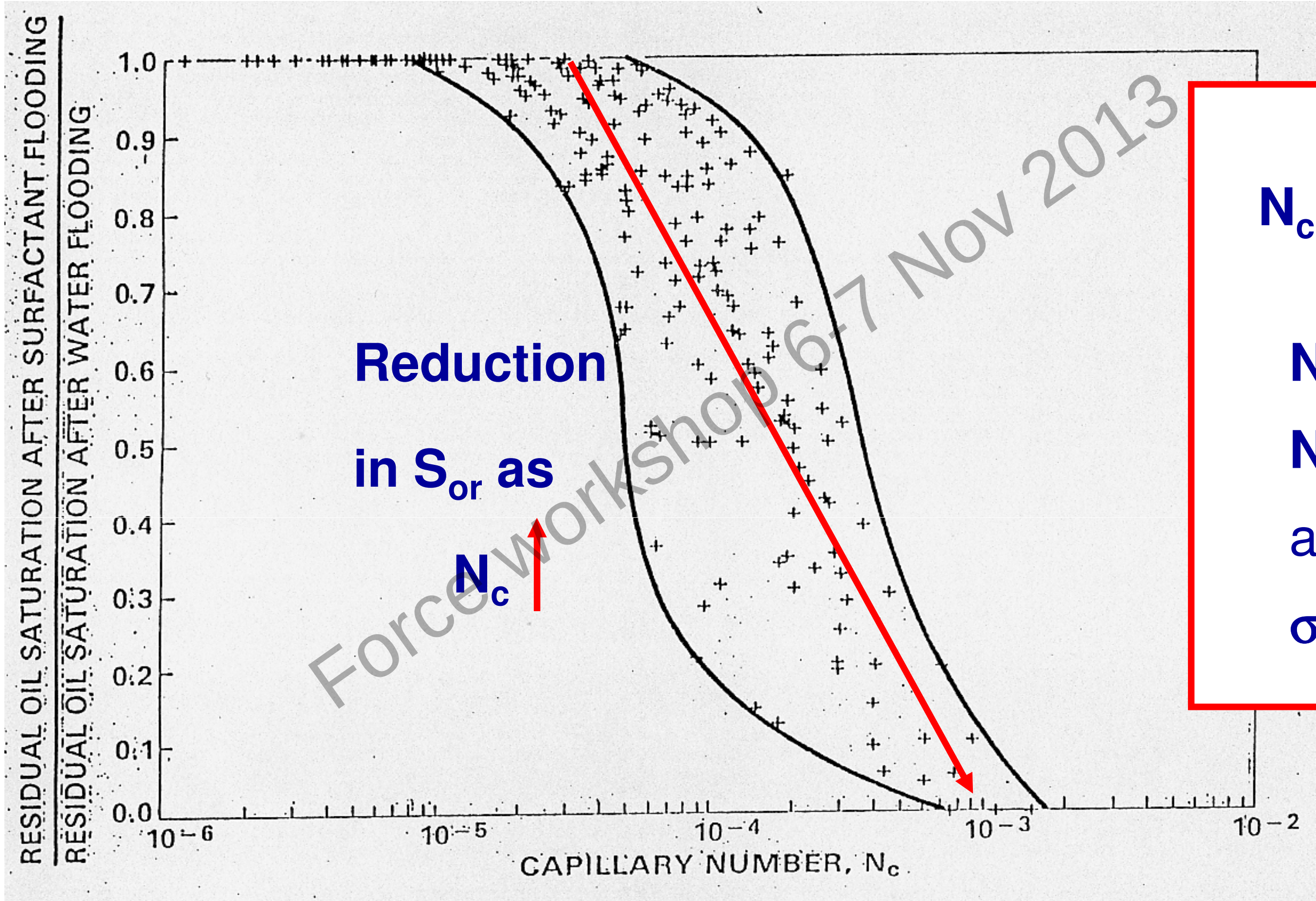


LOWER interfacial tension, σ, but BY HOW MUCH ??

Define Capillary Number, N_c, as - $N_c = \frac{v.\mu}{\sigma}$

(v = velocity; μ = viscosity; σ = interfacial tension)

Residual oil mobilisation at increased Capillary No.



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

Note that

N_c ↑

as

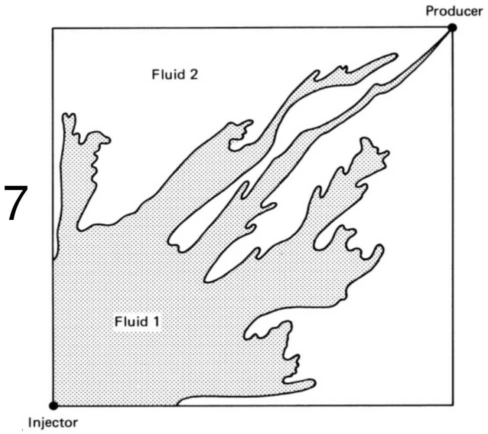
σ ↓

(After Morrow & Chatzis)

Sweep

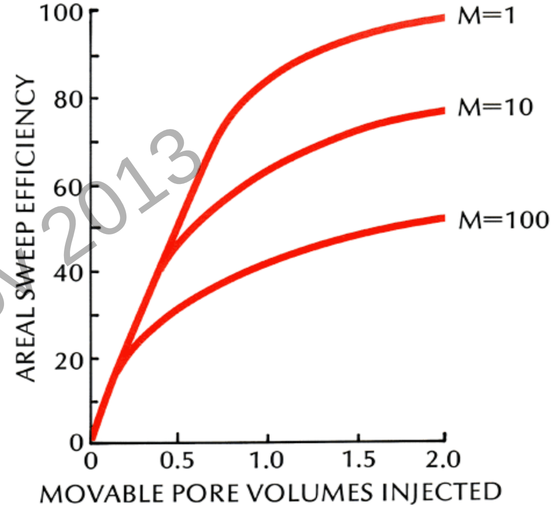
Areal sweep

M=17

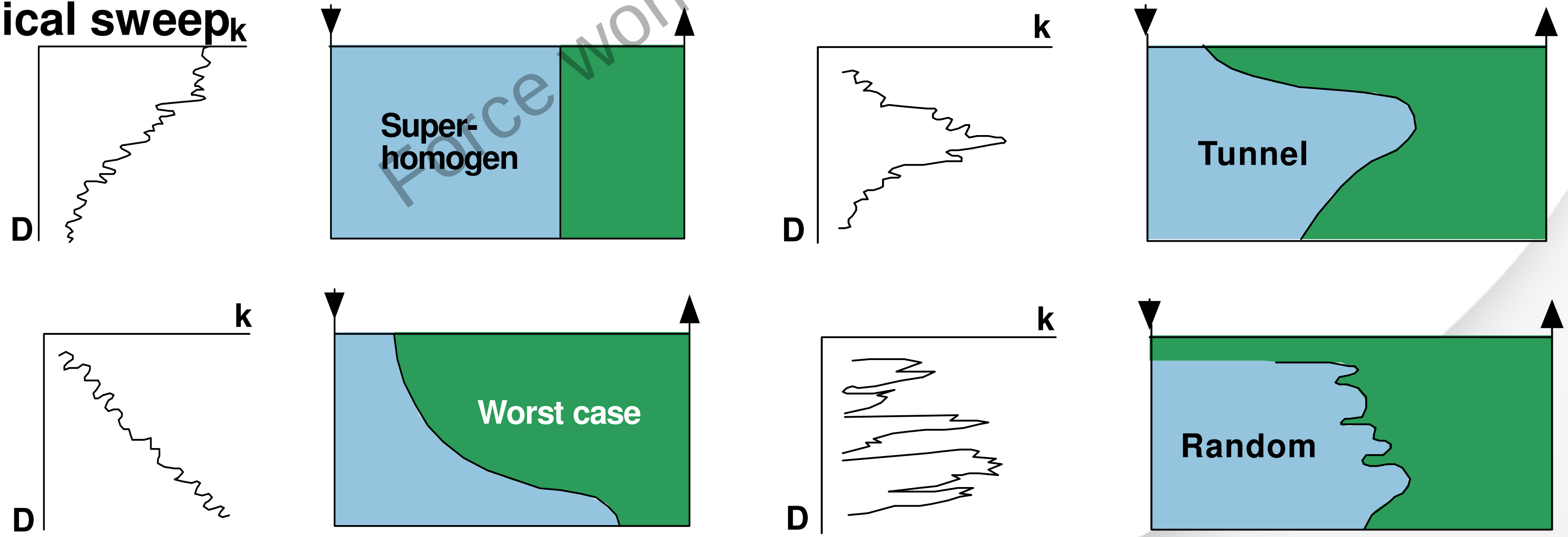


$$M = \frac{K'_{rw}/\mu_w}{K'_{ro}/\mu_o}$$

M < 1 stable front



Vertical sweep



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**
  - CO_2
  - Inert gas N_2
  - Miscible hydrocarbon slug
  - Enrich gas
  - High pressure lean gas

Low salinity water flood
Foam
WAG
Hybrid processes

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EOR experience North Sea reservoirs

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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

Challenges	**Actions**
Identify undrained area	4D seismic and EM
Well distance	drill cheap/fast new wells
Well placement	sidetrack injectors into the oil zone
Logistics	minimize the amount of chemicals for EOR

Maximizing oil recovery for Norwegian oil and gas fields

Challenges	Actions
Identify undrained area	4D seismic and EM
Well distance	drill cheap/fast new wells
Well placement	sidetrack injectors into the oil zone
Logistics	minimize the amount of chemicals for EOR

Use solved challenges to activate EOR

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)

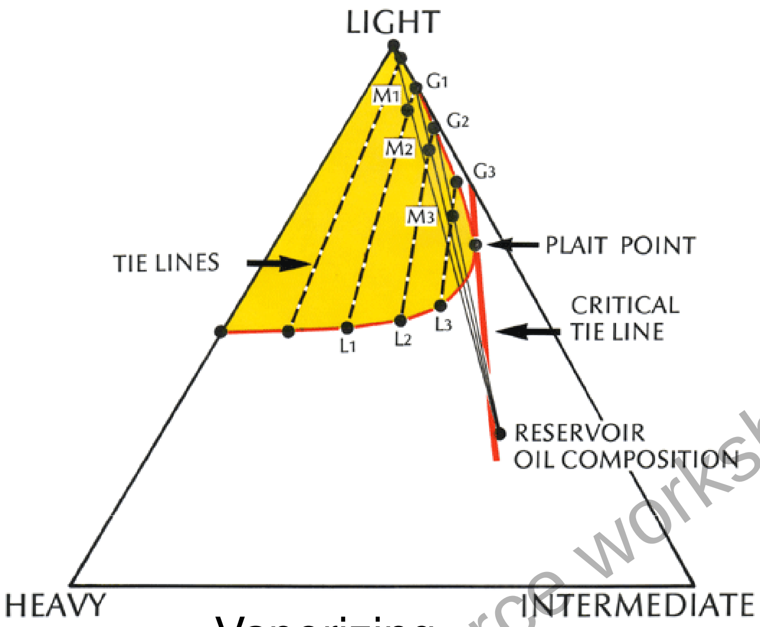
Foam and FAWAG
(Brage, Oseberg, Snorre, Veslefrikk, ++)

Gas injection EOR

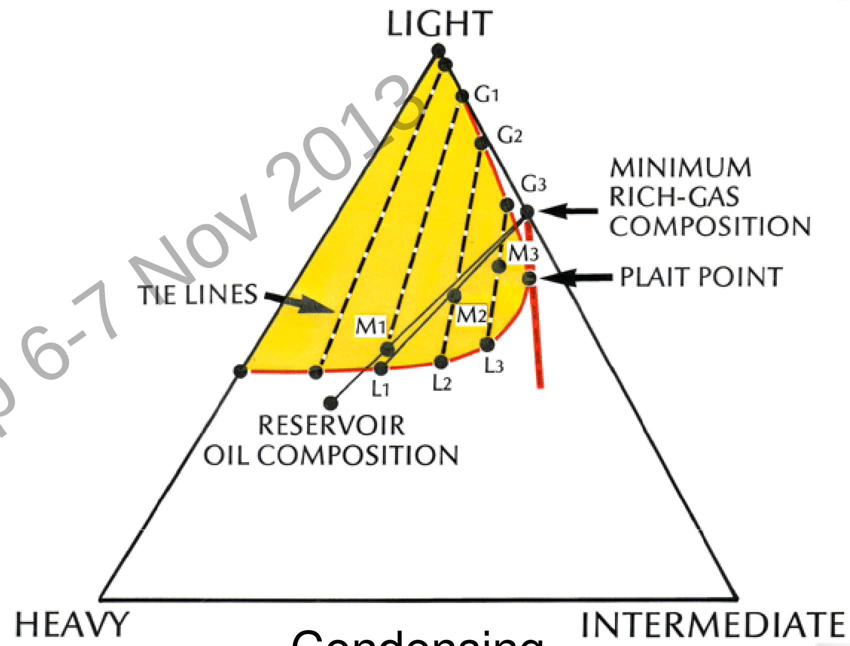
Gas processes

- Miscible gas
- WAG
- Foam
- CO_2 (EOR and sequestration)

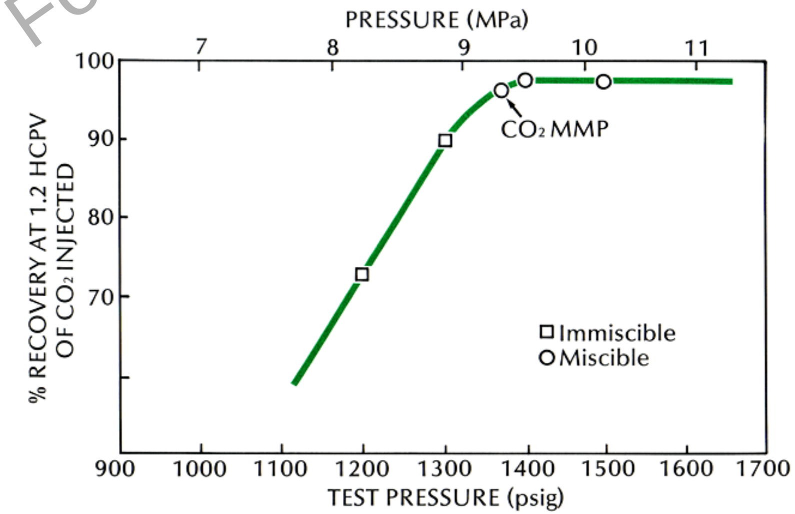
Multi-contact miscible gas injection



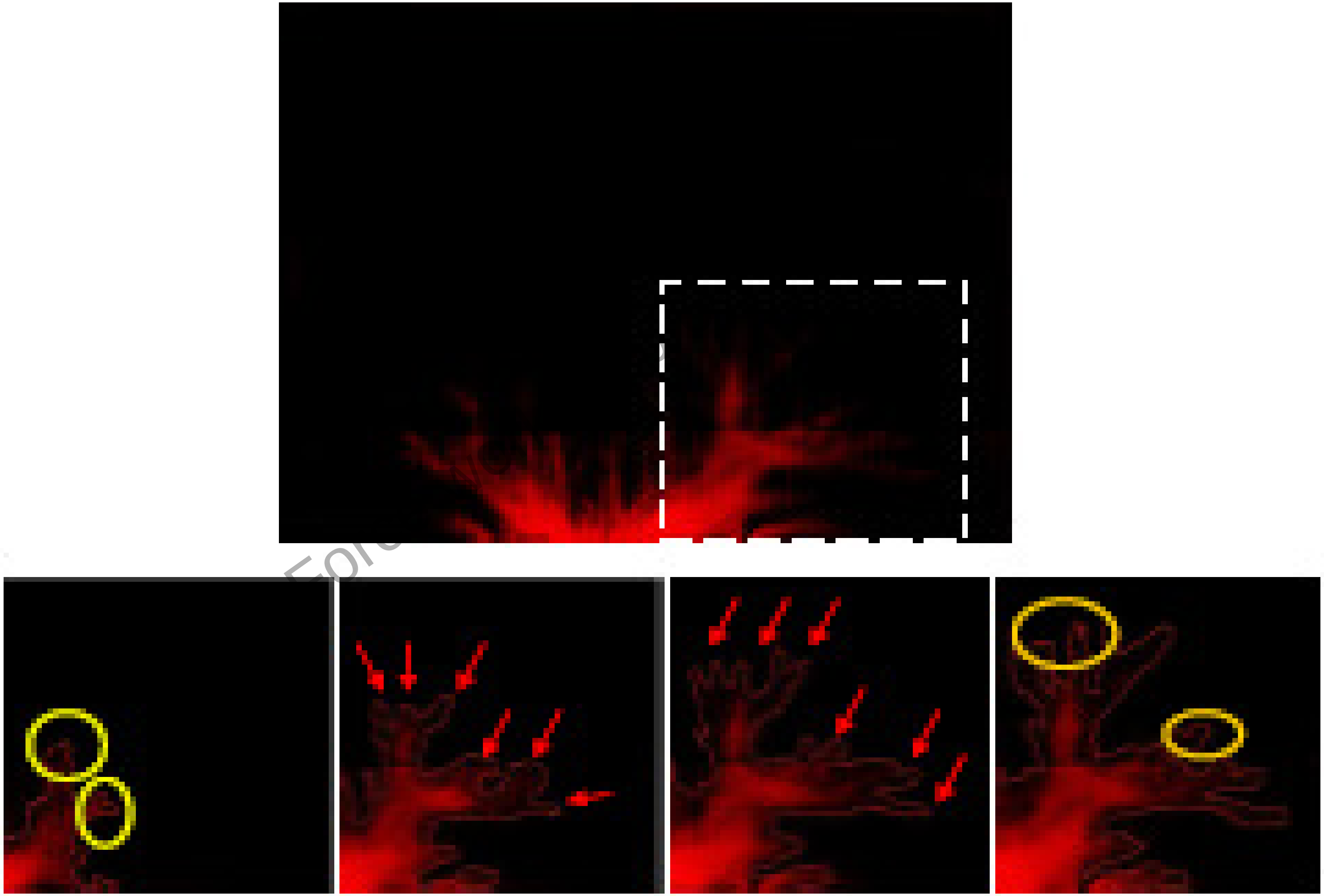
Vaporizing



Condensing



Viscous fingering



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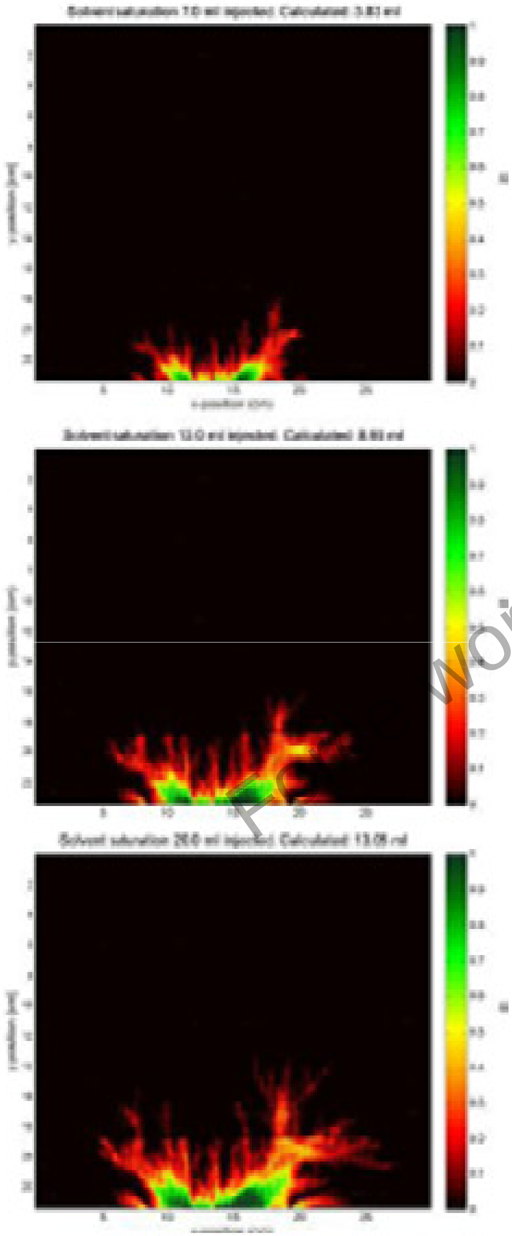
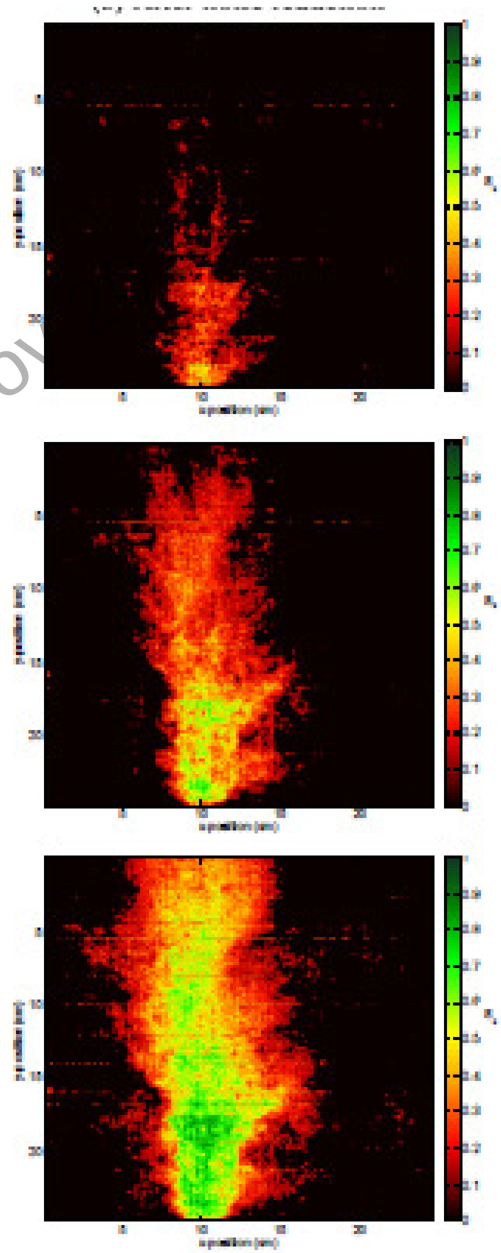
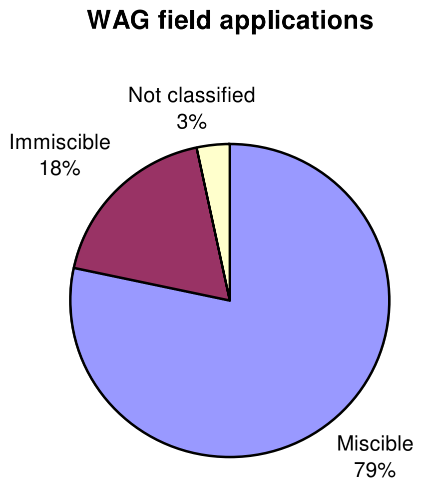
Sandstone



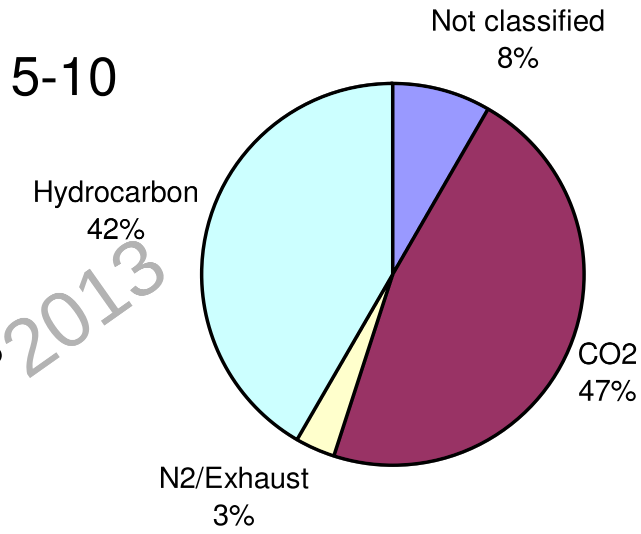
Carbonates





Average increased recovery : 5-10 % OOIP

Miscible applications : 9.7 %
Immiscible applications : 6.4 %



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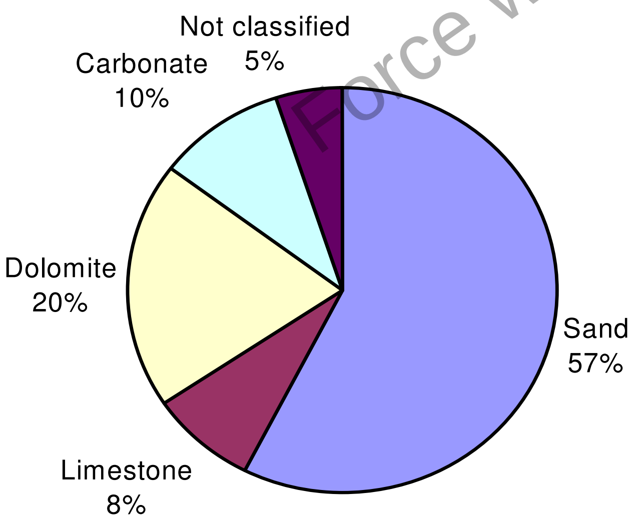
WAG



Gases injected in WAG

Average increased recovery : 5-10 % OOIP

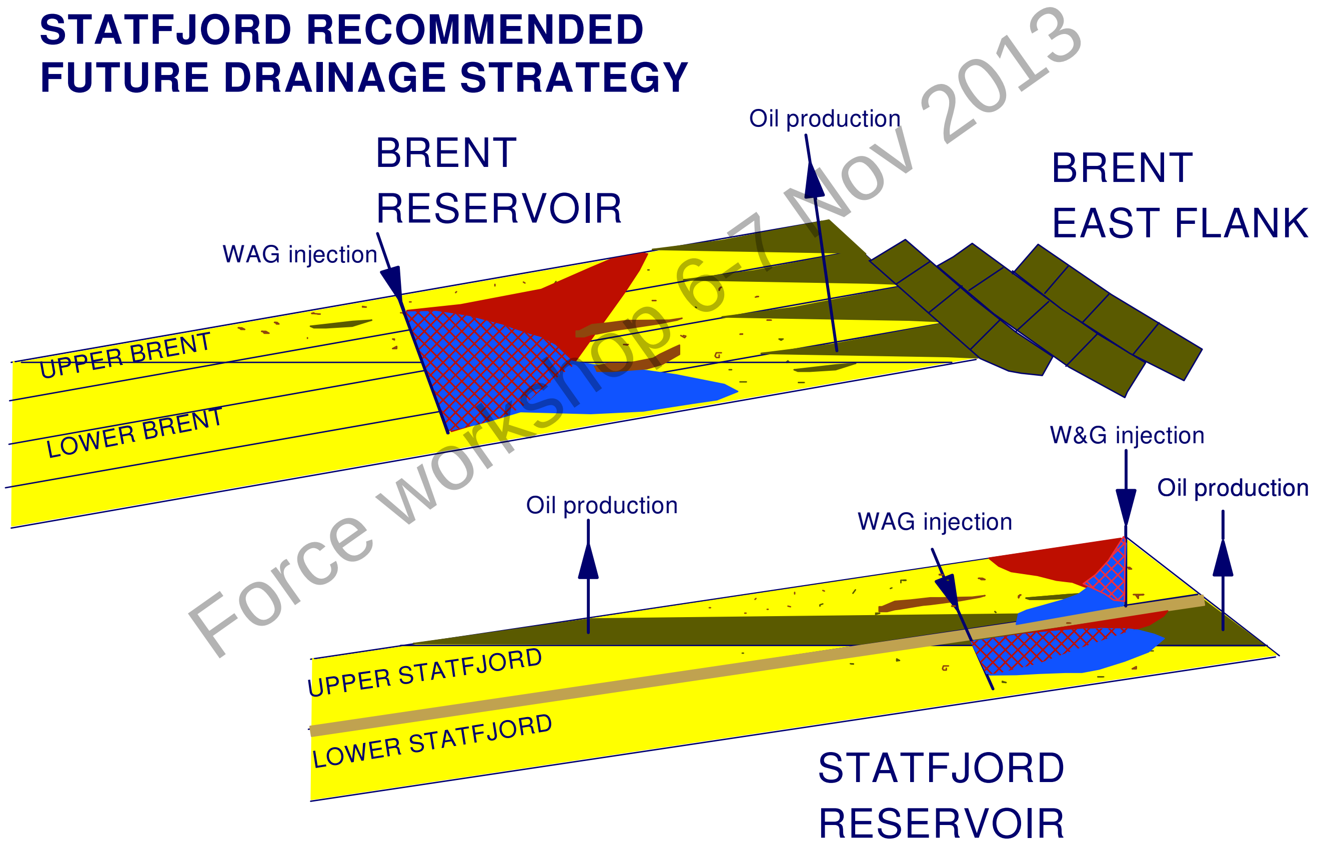
CO_2 applications : 8 %
Hydrocarbon applications : 5 %

Carbonates / Dolomites have higher average recovery than sandstones

Formation

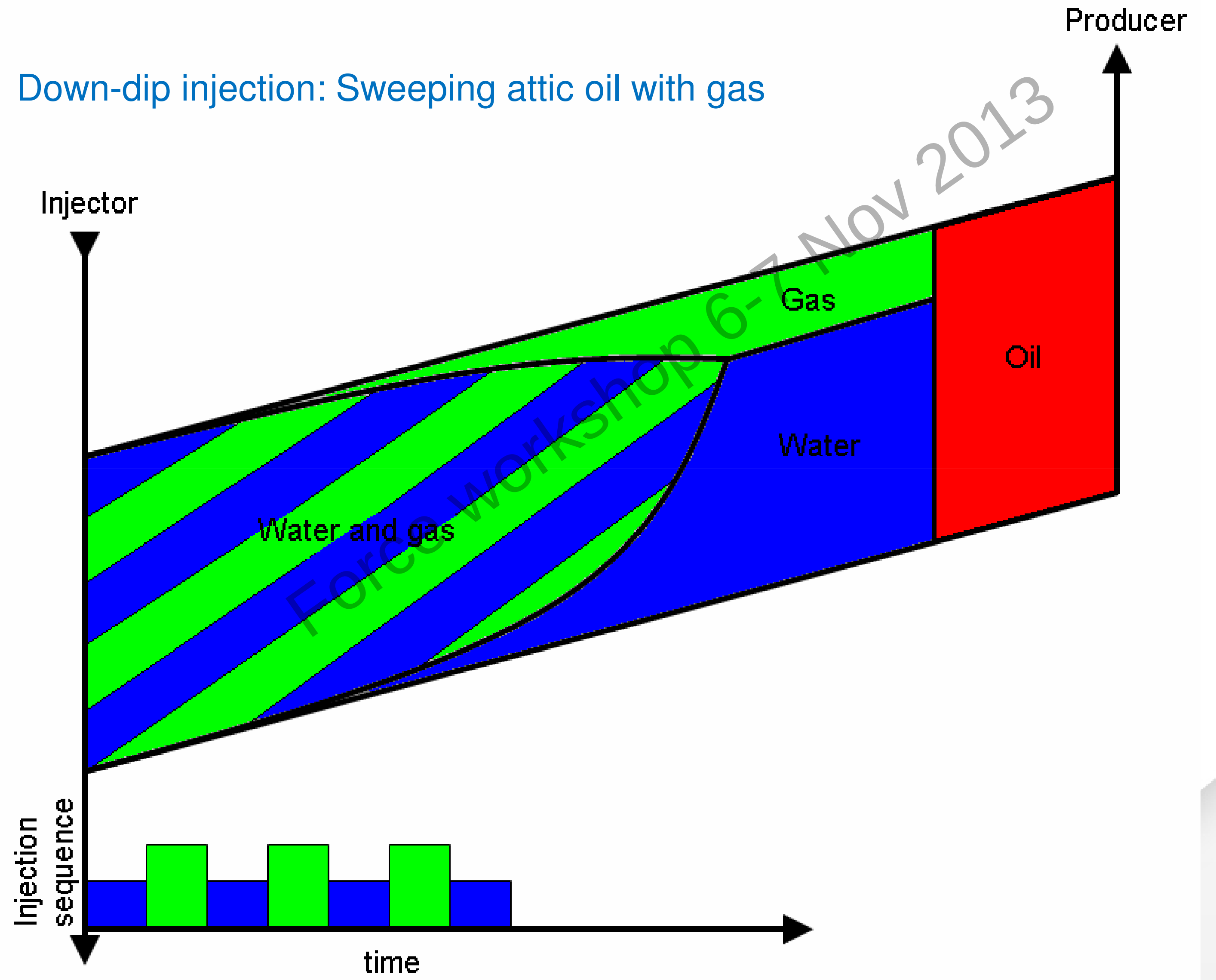
Gas based methods, example

STATOIL



Gas and water improving vertical sweep

Down-dip injection: Sweeping attic oil with gas



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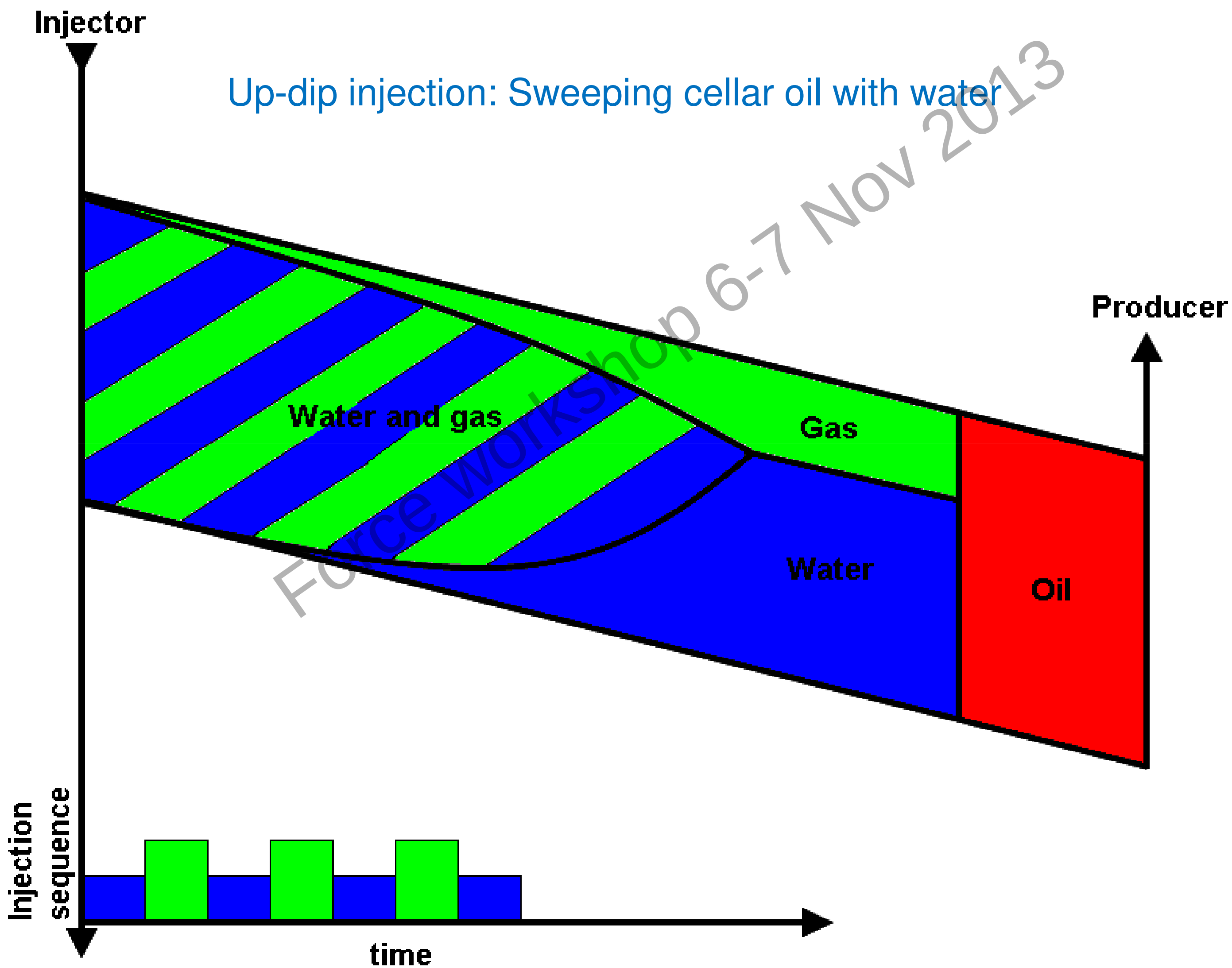
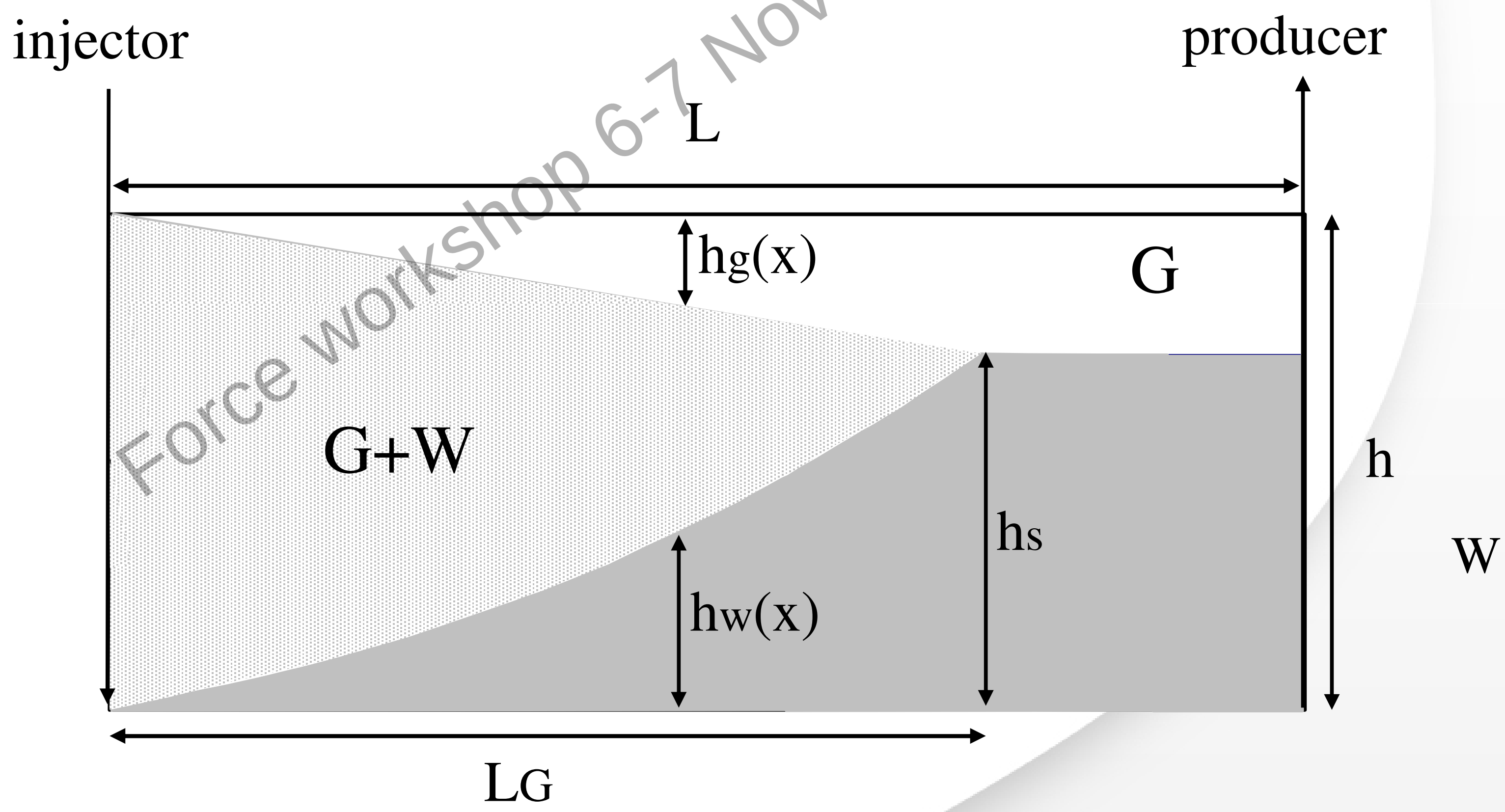


Stone - Jenkins

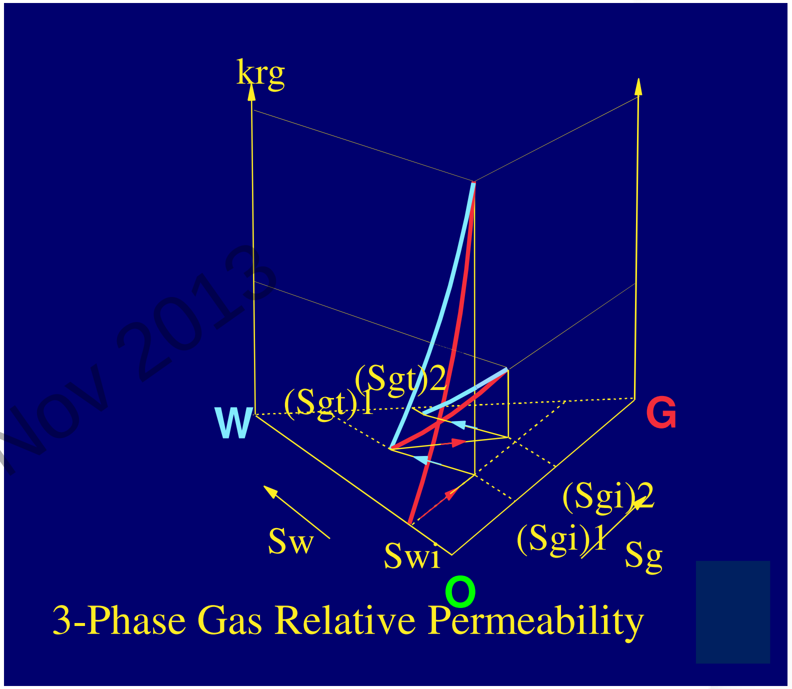
Calculation of extent of the WAG three-phase zone based on two-phase flow only

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



BUT Som (3ph) << 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

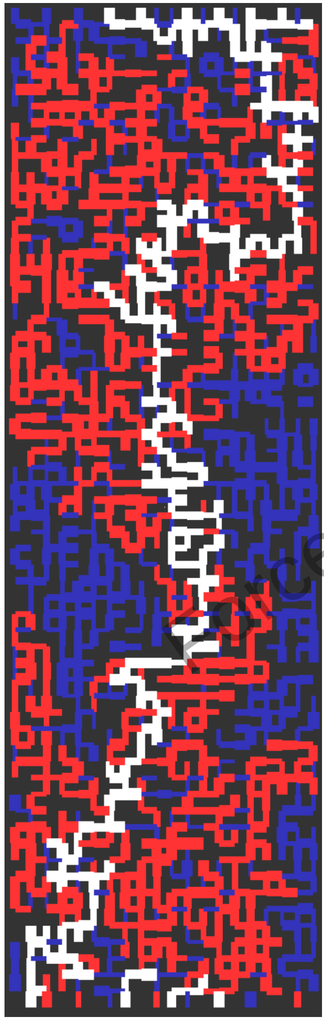
Immiscible WAG: mechanism - redistribution

RED
- oil

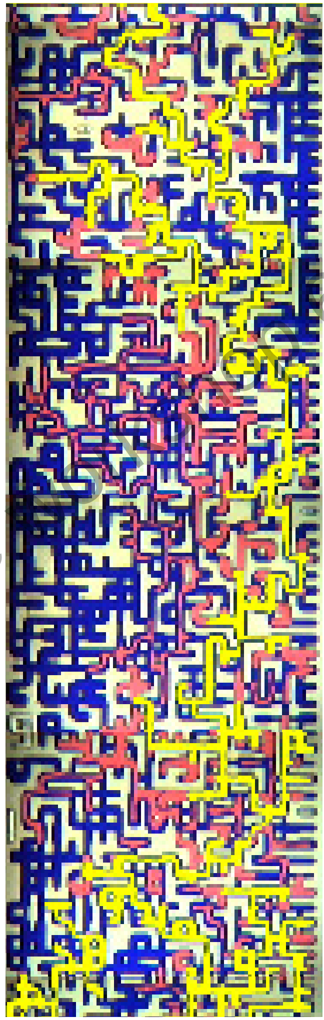
BLUE
- water

WHITE/ YELLOW
- gas

σ_{go}=15 mN/m

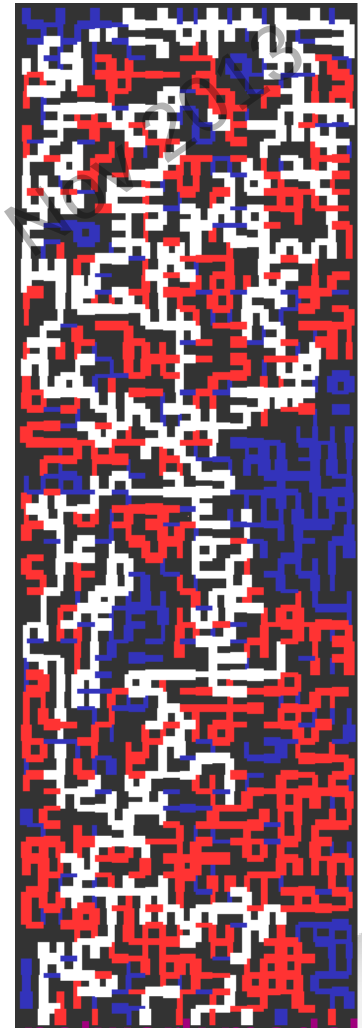


network model

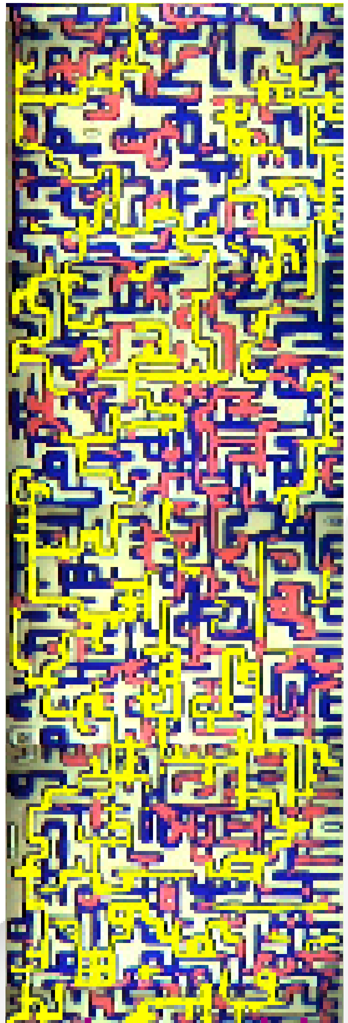


micromodel

first gas flood



network model



micromodel

fifth gas flood

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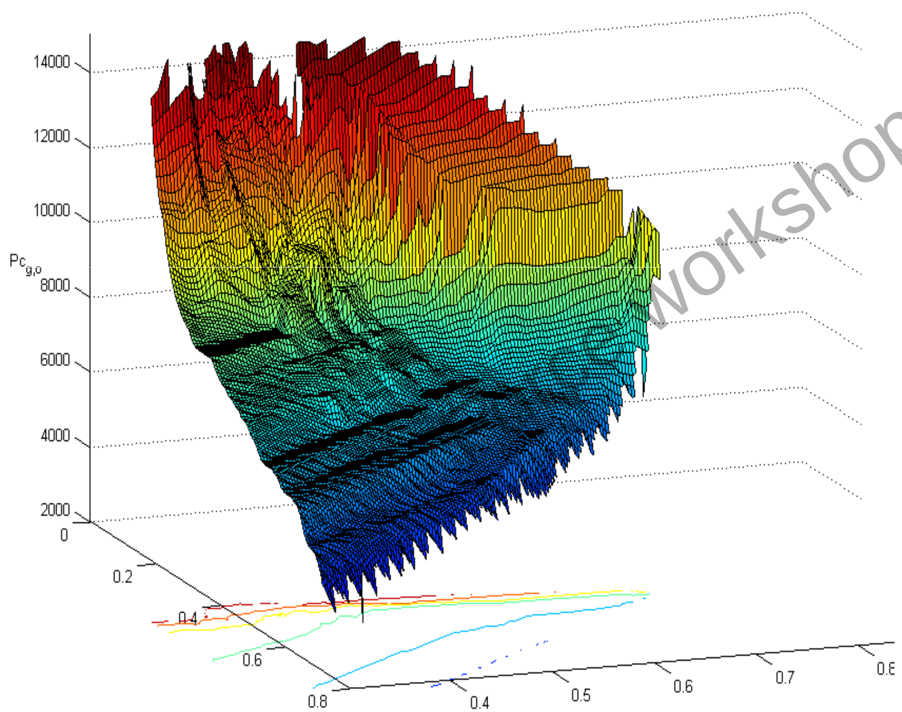
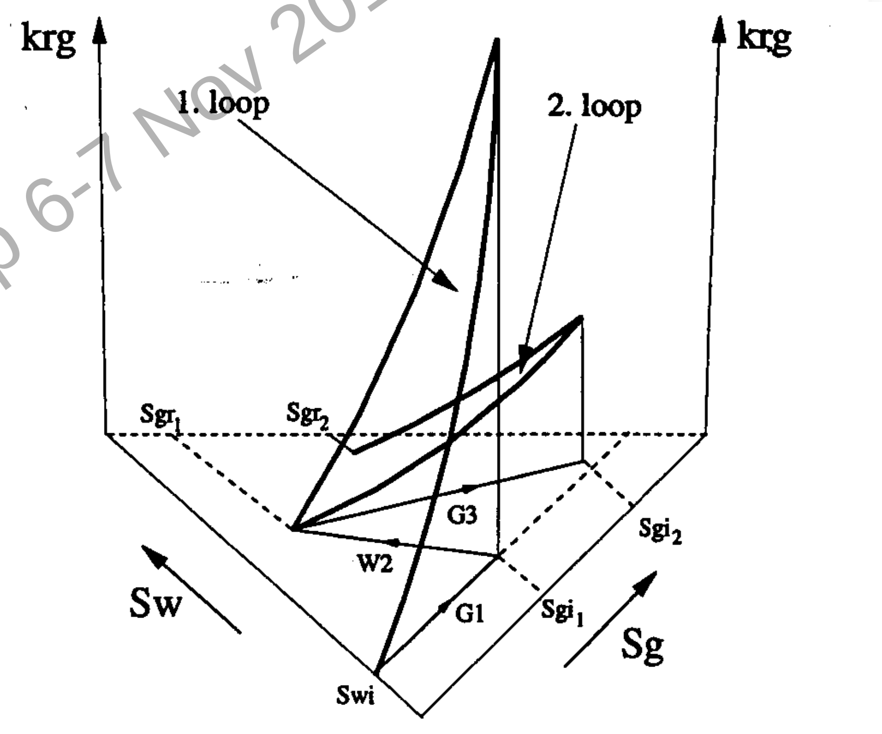
WAG modelling



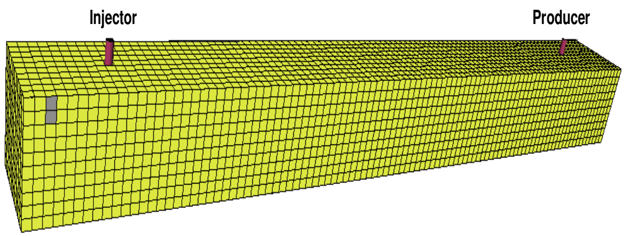
three-phase Pc (go)



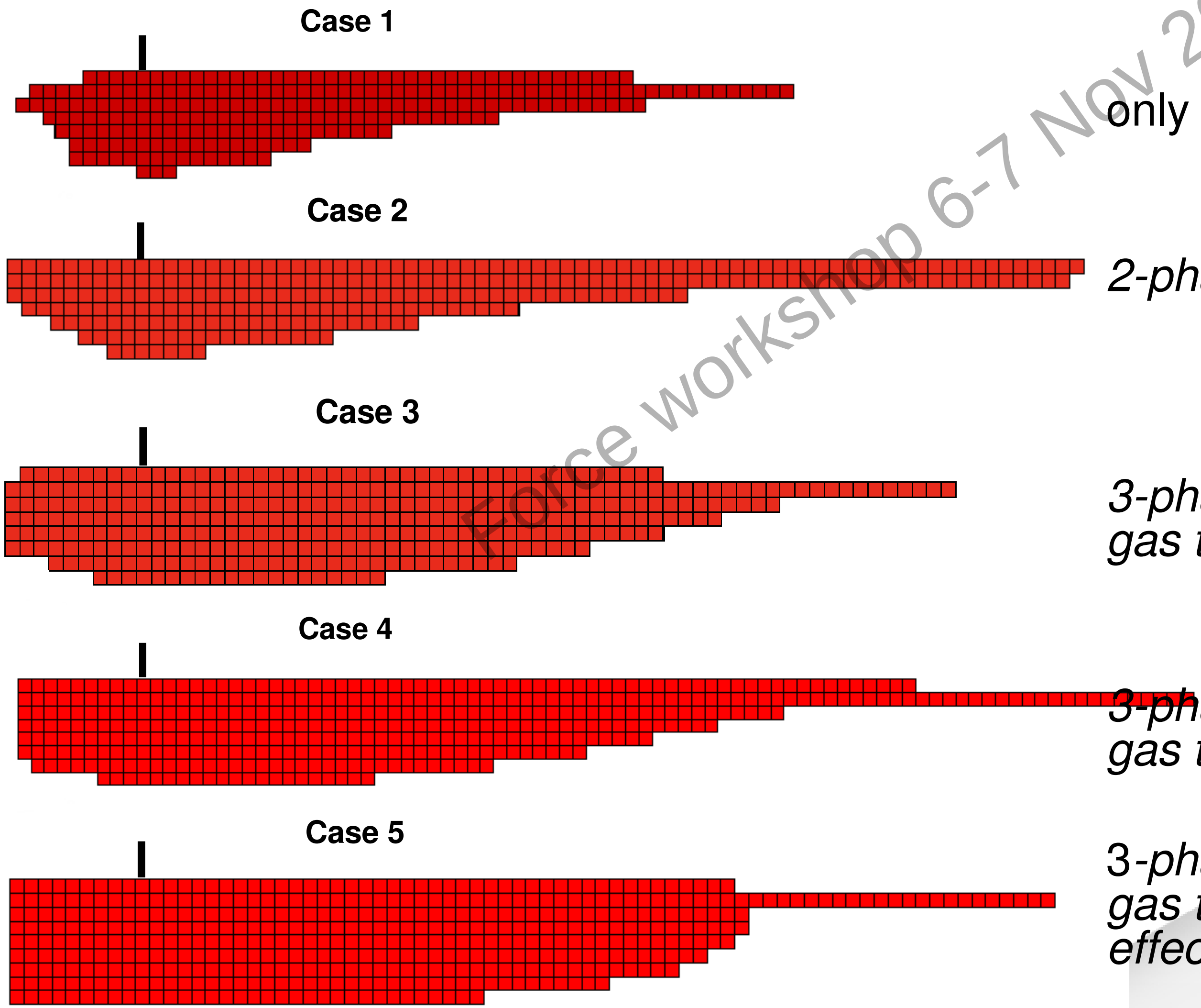
Larsen and Skauge, SPEJ
Skauge and Dale, SPE 111435

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



Skauge and Dale, SPE 111435



only 2-phase rel perm

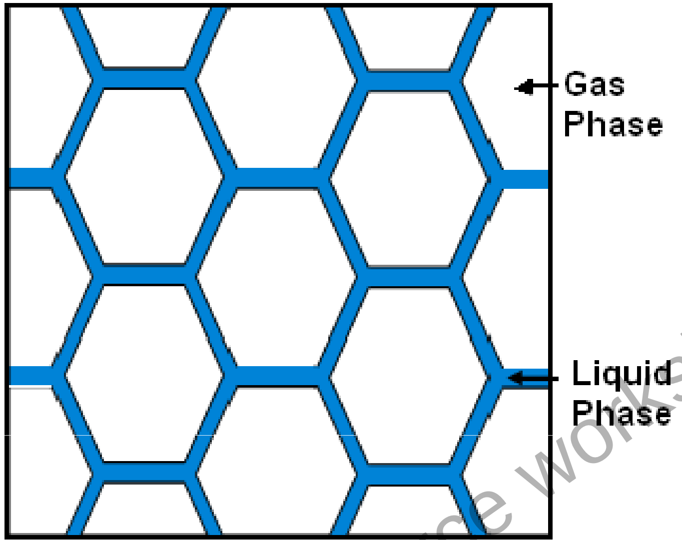
2-phase rel perm including Pc

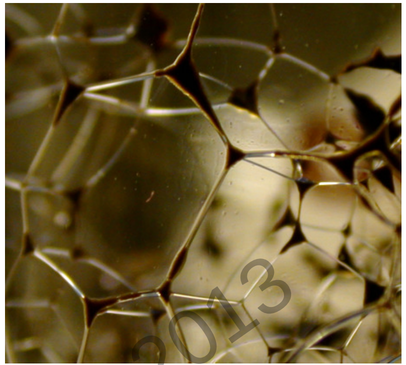
3-phase rel perm hysteresis and gas trapping

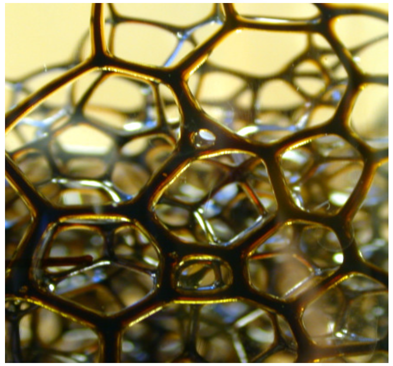
3-phase rel perm hysteresis and gas trapping including Pc

3-phase rel perm hysteresis and gas trapping including Pc and the effect of Pc on rel perms

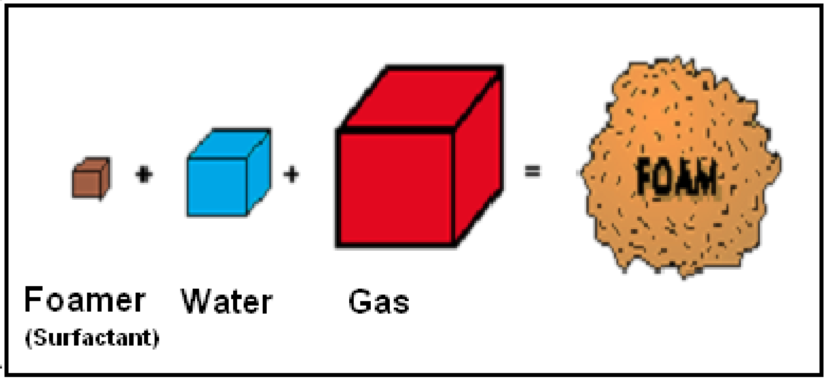
Foam







- 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



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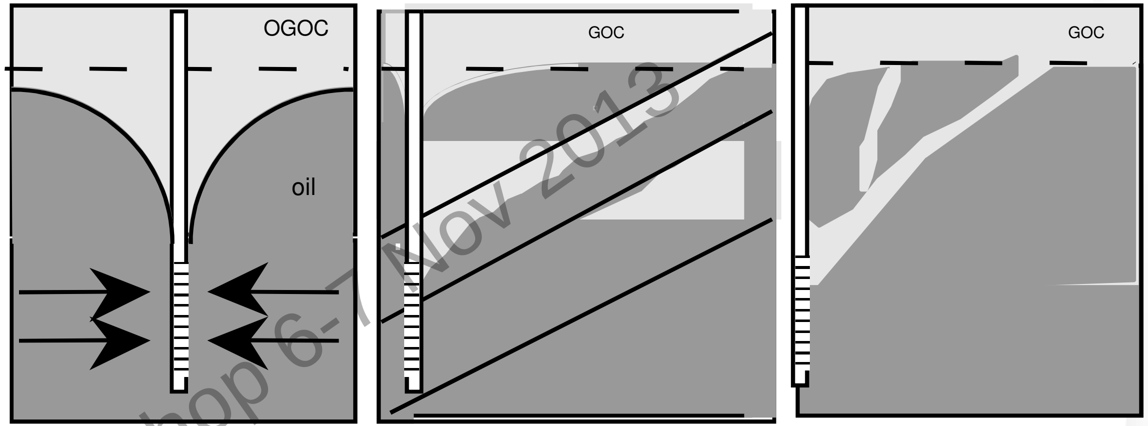
Foam Applications

Near the producer:

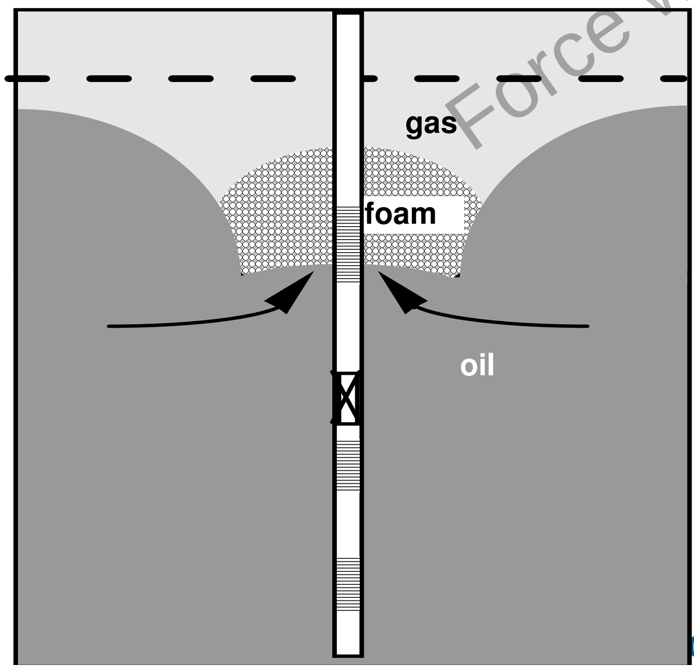
a) Gas coning.

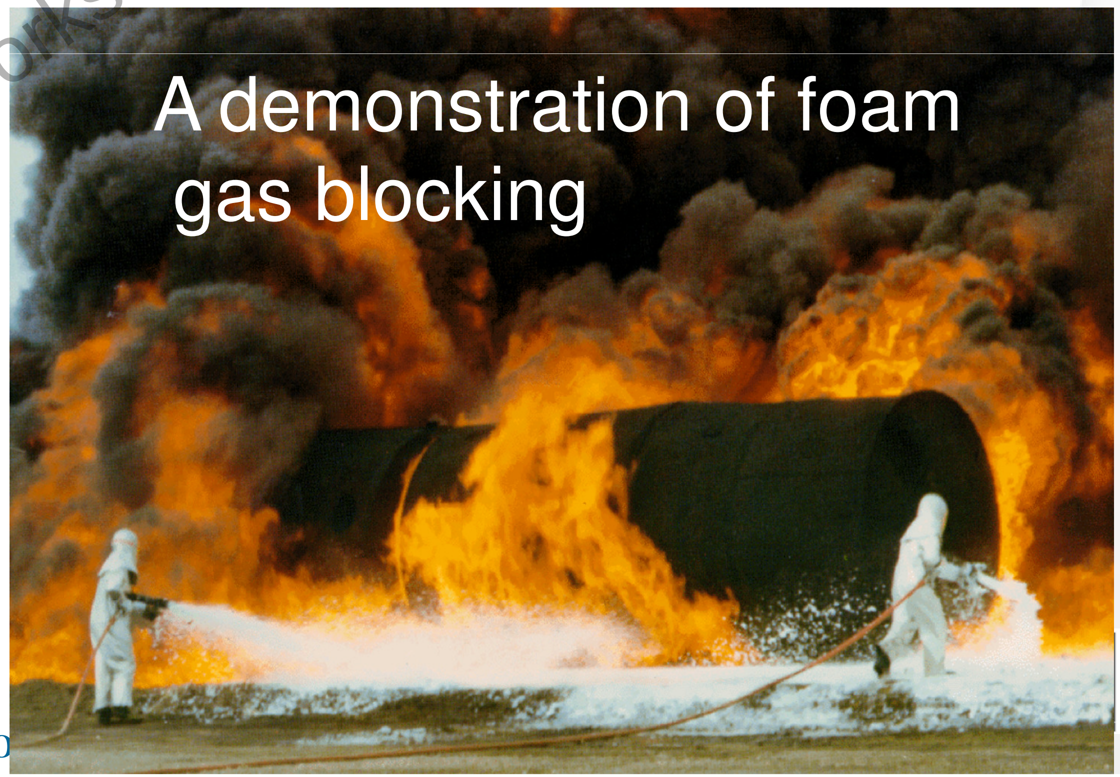
b) Gas cusping.

c) Gas channelling in fractures



Foam blocking
a gas cone





Foam trials North Sea Area

Production well treatments

- Oseberg
  - B-27 1994
  - B-38 1996
- Beryl
  - B-30z 1994
- Snorre
  - P-18 1996

Foam for mobility control

- Snorre
  - Central Fault Block
  - (P-25-P18A) 1997/98
  - Western Fault Block
  - (P32-P39) 1999/2000
- Brage 1998

Waterflood EOR

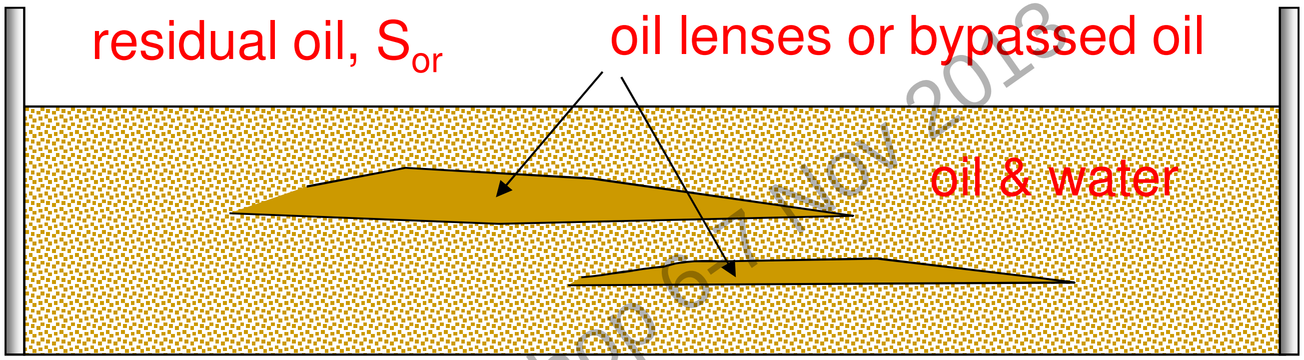
Waterflooding EOR

- Low salinity
- Hybrid EOR
- Surfactants (lower IFT)
- Polymer flooding (sweep ++)
- LPS (microscopic diverging)
- Diverging techniques
- MIOR
- and more

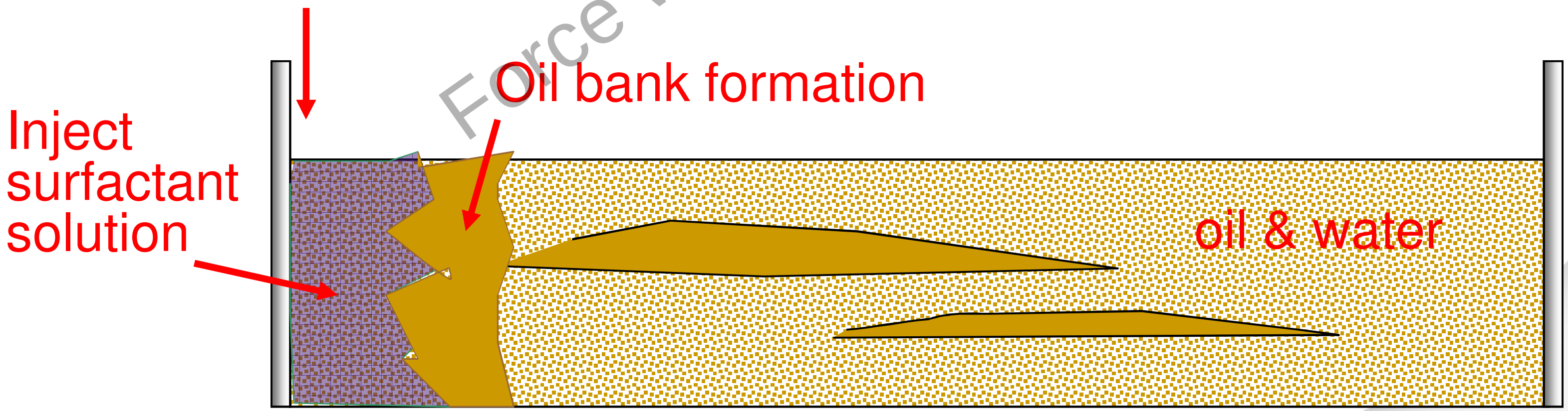
Conventional Chemical Methods for Enhanced Oil Recovery

- 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

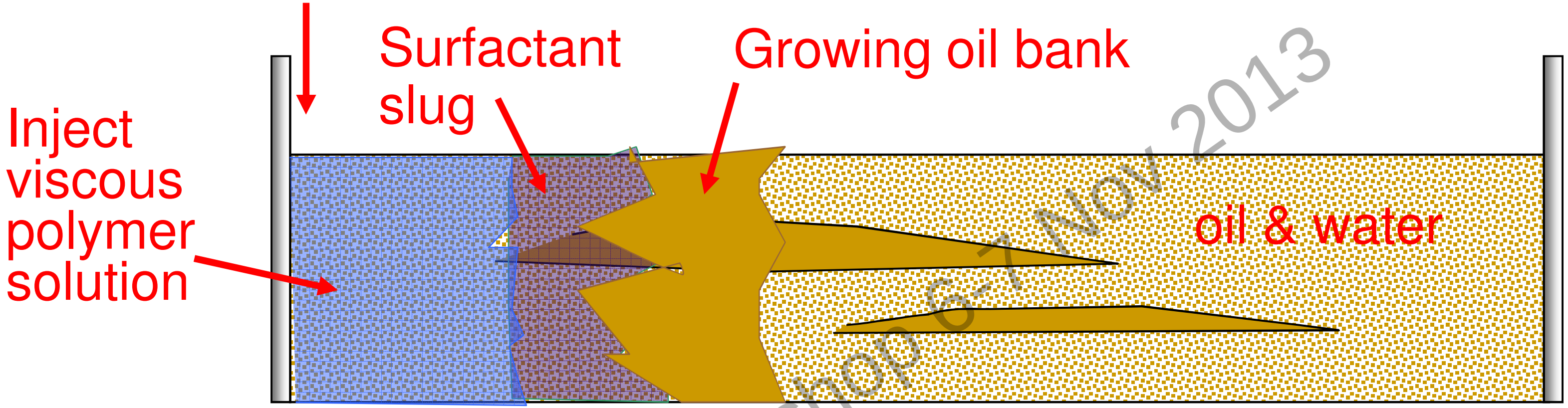


1. Situation after some time of waterflooding; S_{or} and bypassed oil

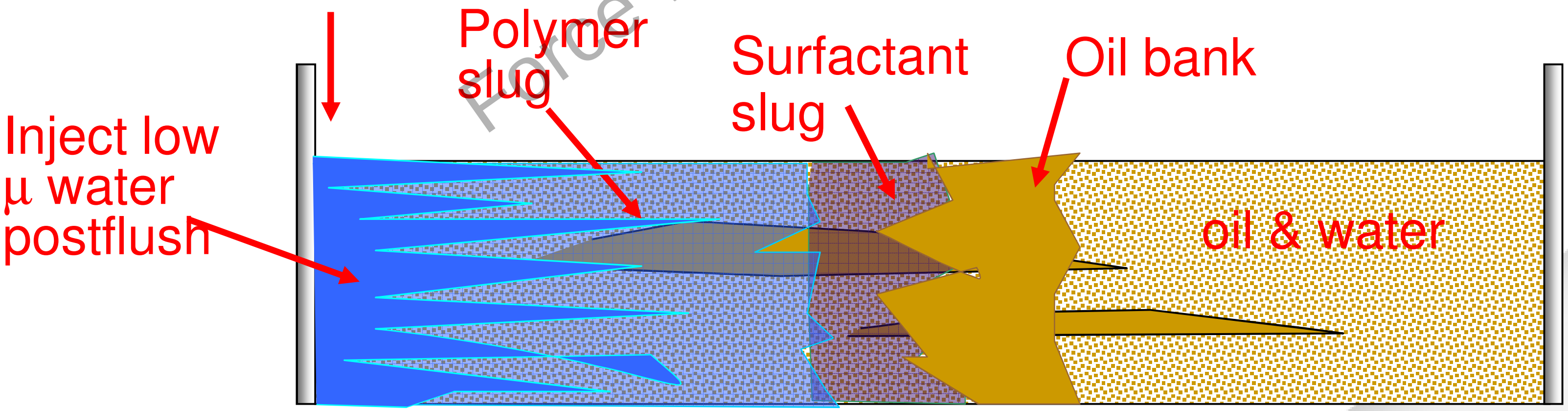


2. Inject aqueous surfactant solution - mobilise oil - form “oil bank”

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

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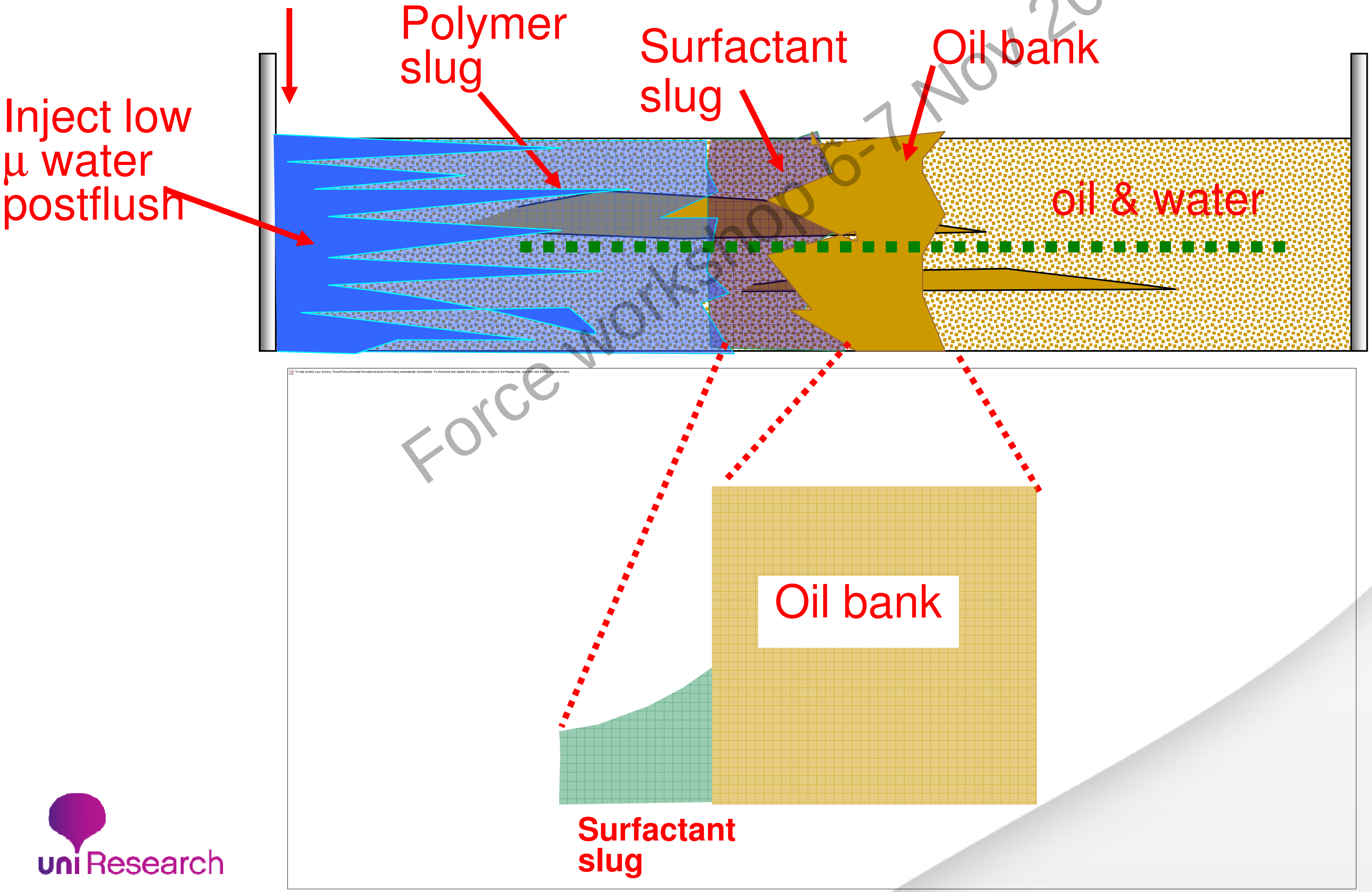
Surfactant floods - frontal structure of oil bank

Note the profile of the oil saturation in 1D



Classical Surfactant Enhanced Oil Recovery

- Surfactants has 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**

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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

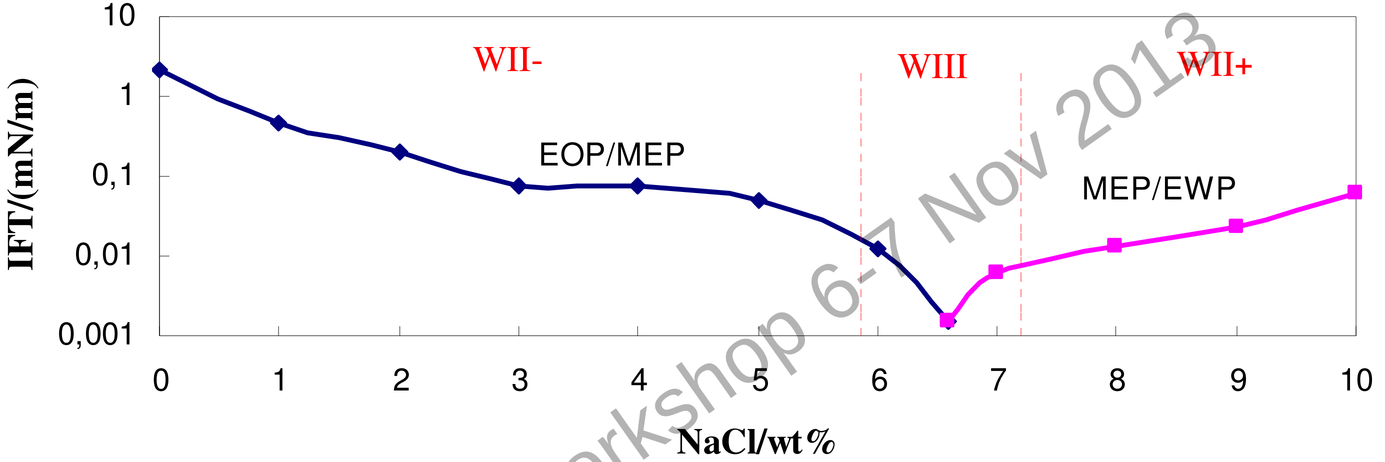
- Optimizing a surfactant flooding process is a compromise between

- 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



				S*									
NaCl %	0	1	2	3	4	5	6	6,6	7	8	9	10
Phase behaviour	II-	II-	II-	II-	II-	II-	III	III	III	II+	II+	II+
IFT/(mN/m)	2,18	0,46	0,21	0,075	0,077	0,05	~0,013	0,0015	~0,006	0,013	0,023	0,061

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

NaCl wt%	0	1	2	3	4	5	6	7	8	9	10
Appearance	C	C	C	C	P	P	T	P	P	P	O
Activity	100	100	100	100	79	97	100	98	98	98	11
Retention (mg/g)		0,14		0,15			1,5			1,76	
IFT (mN/m)	2,18	0,46	0,21	0,075	0,077	0,05	0,0015*		0,013	0,023	0,061
Phase behaviour				WII-			WIII	WIII	WII+	WII+	WII+

* IFT at S* = 6.6

Alternative?

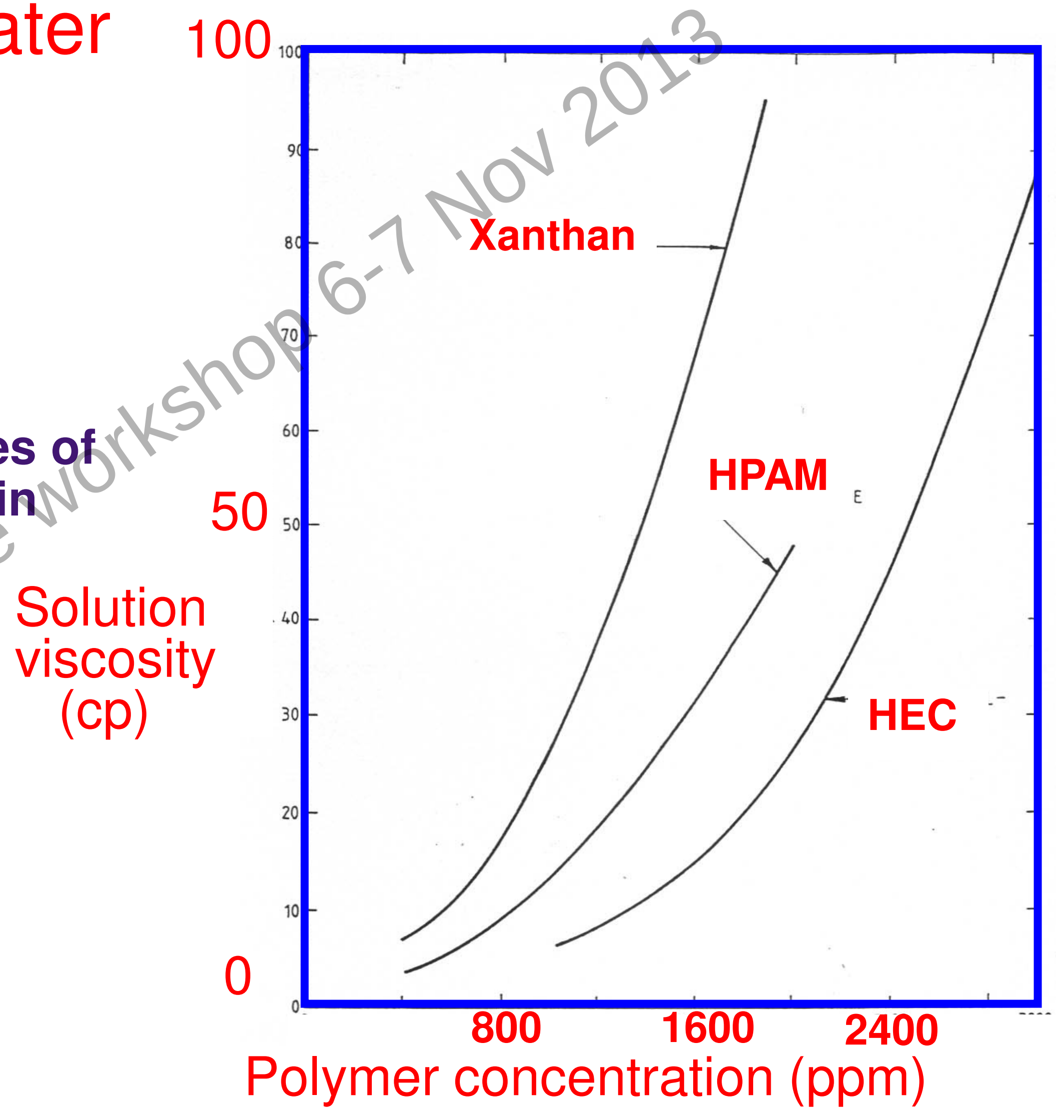
Ultralow IFT, BUT poor solution properties and high retention

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

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

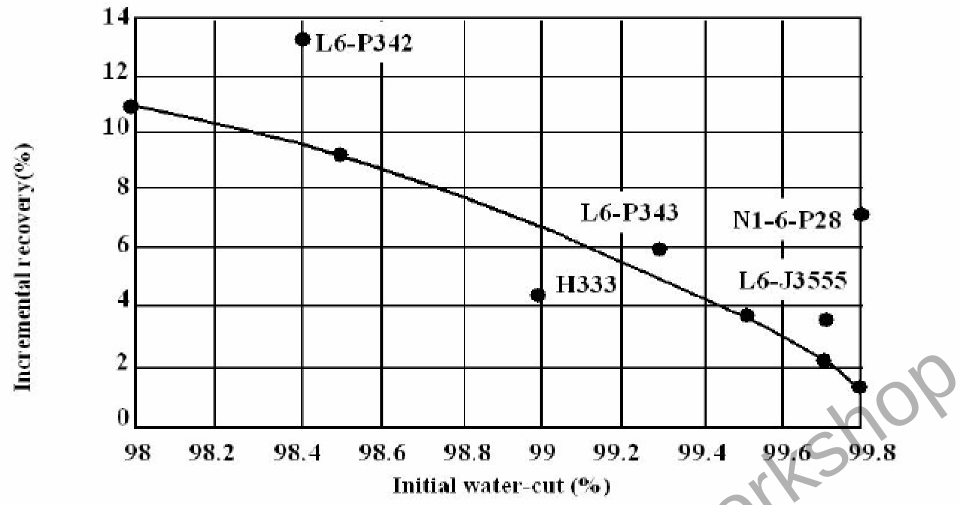


Xanthan - a biopolymer

HPAM - hydrolysed poly acrylamide

HEC - hydroxy ethyl cellulose

Daqing Polymer Injection



g. 7 Relationship of incremental recovery by polymer flood versus initial water-cut

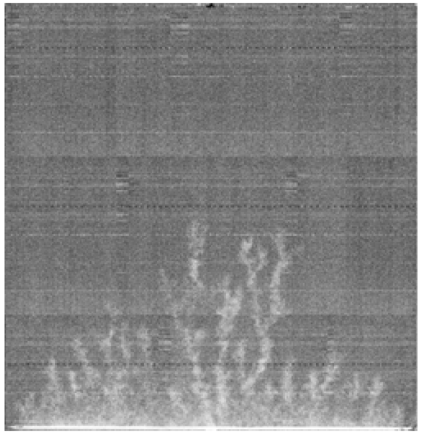
Project Description:

- **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**

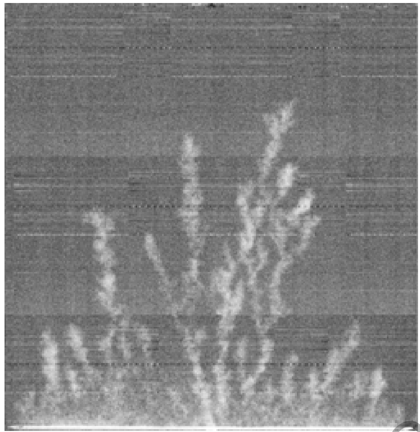
Lessons Learned:

- **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**

Waterflooding at high adverse mobility ratio

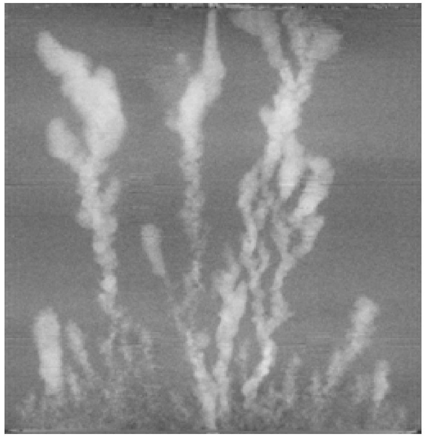


0.01 PV



0.02 PV

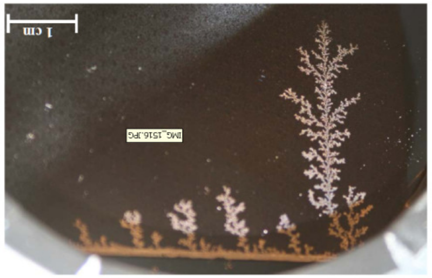
0.04 PV



0.14 PV

0.53 PV

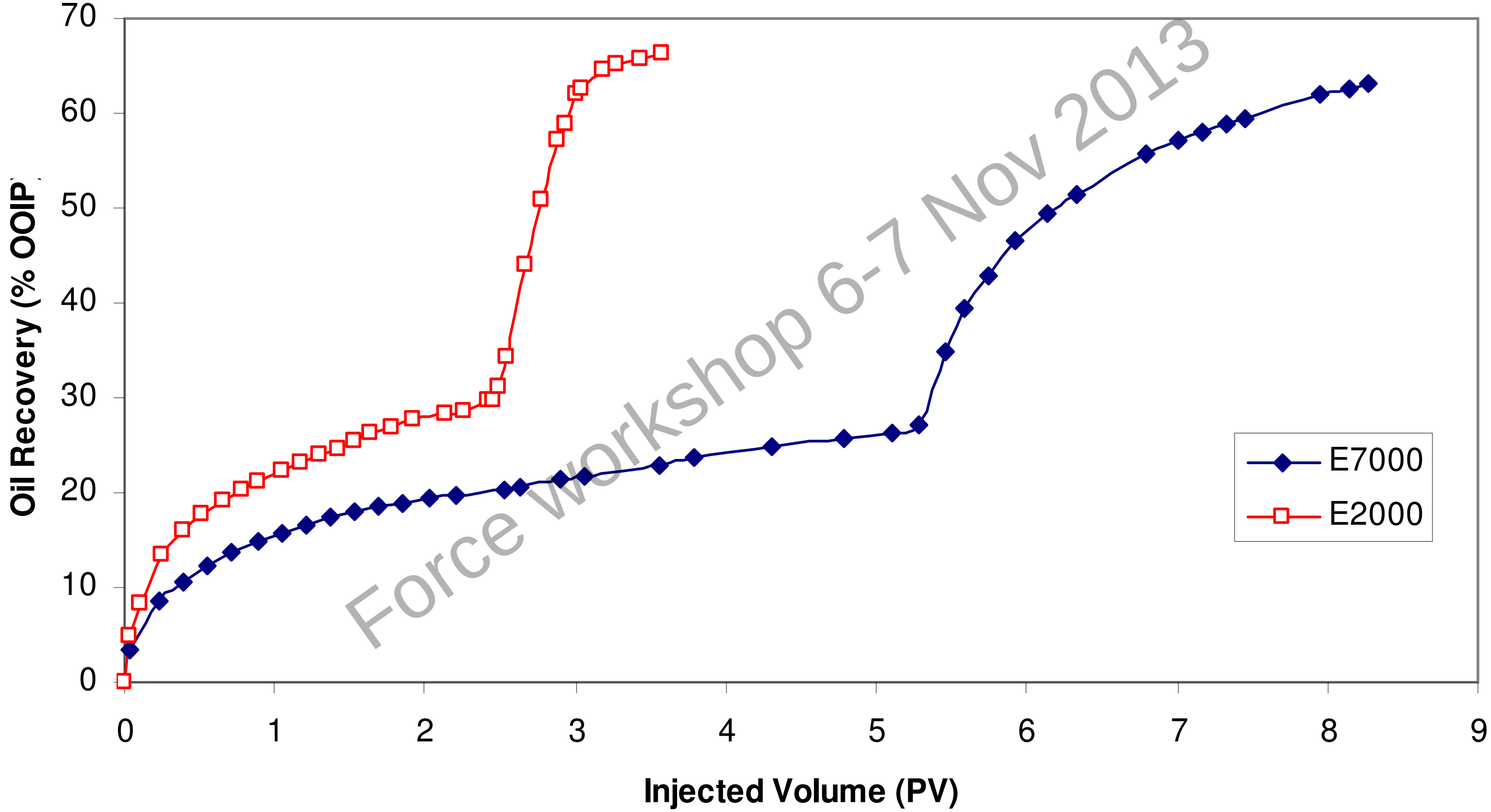
2.3 PV



Mohanty et al 2012

Skauge, A., Ormehaug, P:A., Gurholt, T., Vik, B., Bondino, I., and Hamon, G., 2-D Visualisation of Unstable Waterflood and Polymer Flood for Displacement of Heavy Oil, SPE 154292, paper prepared for presentation at the Eighteenth SPE Improved Oil Recovery Symp. Tulsa, 2012

Water- and polymer flood of viscous oils



Skauge, A., Ormehaug, P:A., Gurholt, T., Vik, B., Bondino, I., and Hamon, G., 2-D Visualisation of Unstable Waterflood and Polymer Flood for Displacement of Heavy Oil, SPE 154292, paper prepared for presentation at the Eighteenth SPE Improved Oil Recovery Symp. Tulsa, 2012

Losal – Designer water – Smart water, etc

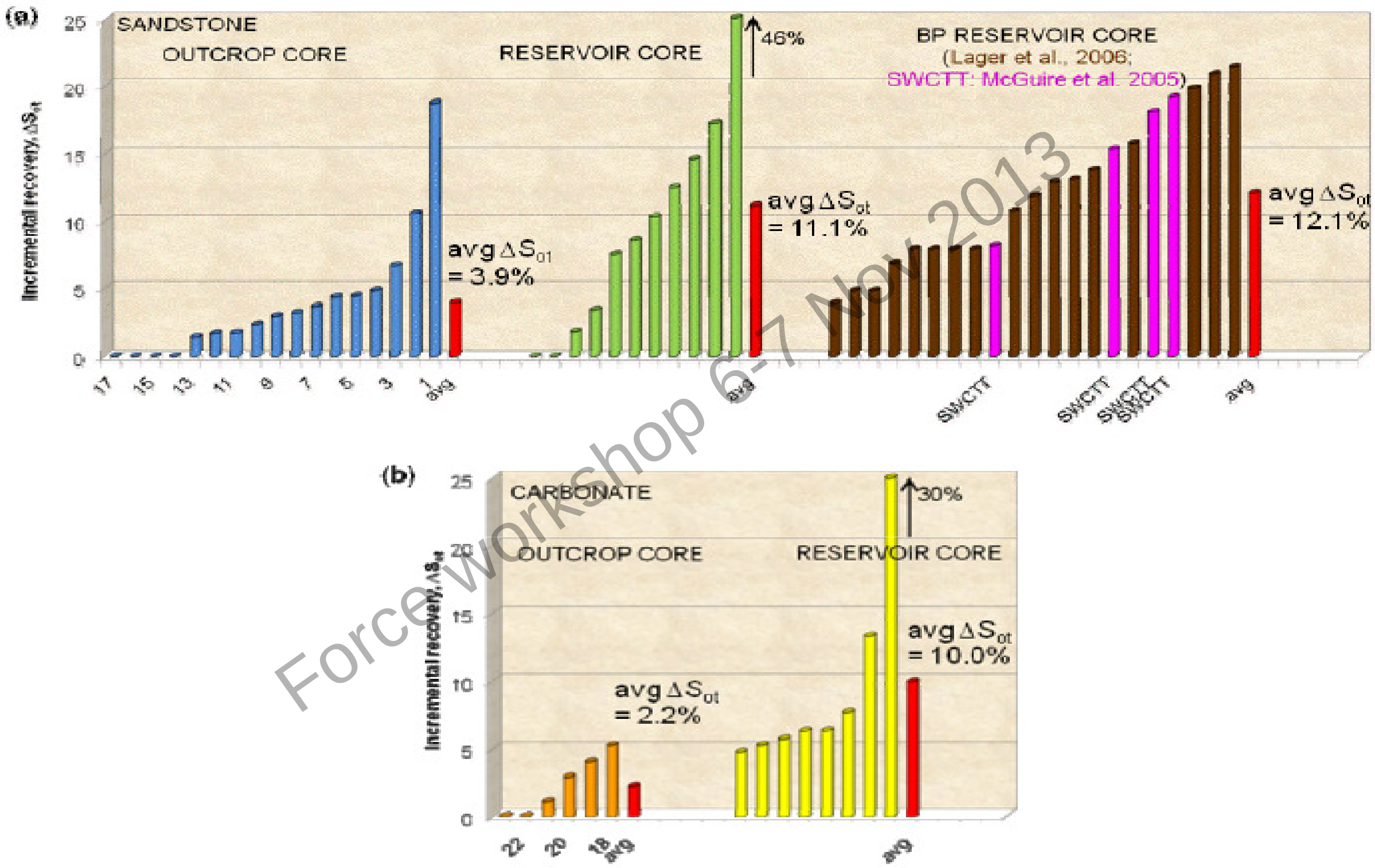


Fig. 6 Incremental tertiary recovery (ΔS_{ot}) by low salinity waterflooding: (a) sandstones and (b) carbonates. Average of 17 outcrop sandstones was 3.9%, for 11 reservoir sandstones was 11.1%, and 12.1% for literature data for reservoir cores or well tests. For outcrop carbonates the average was 2.2% 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

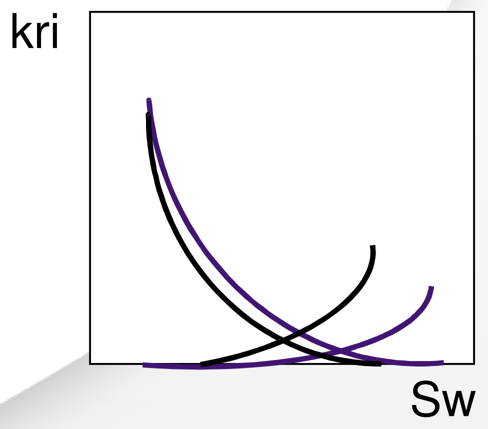
Plus about 20 other suggestions in the literature

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

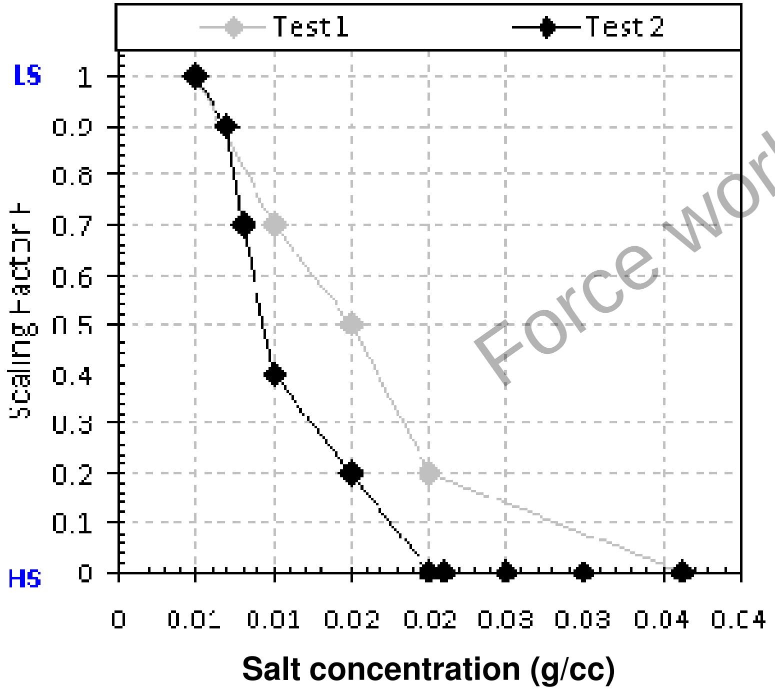
$$k_{ri} = F_1 k_{ri}^L + (1 - F_1) k_{ri}^H$$

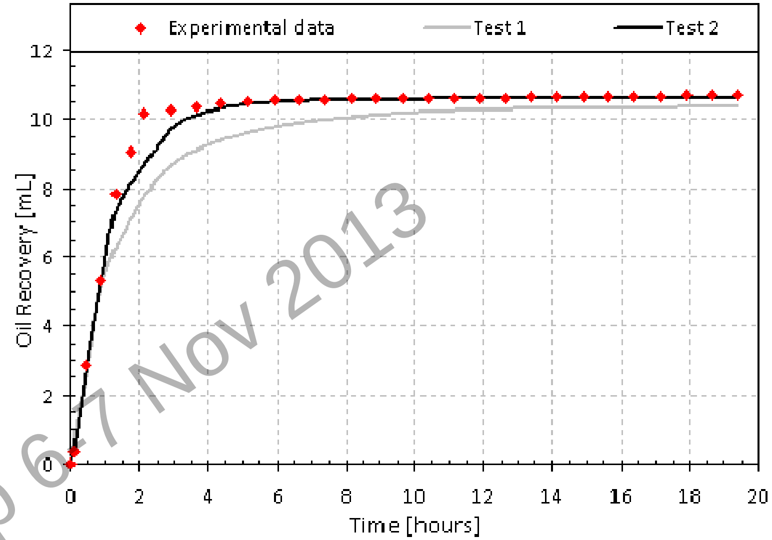
$$P_{cij} = F_2 P_{cij}^L + (1 - F_2) P_{cij}^H$$

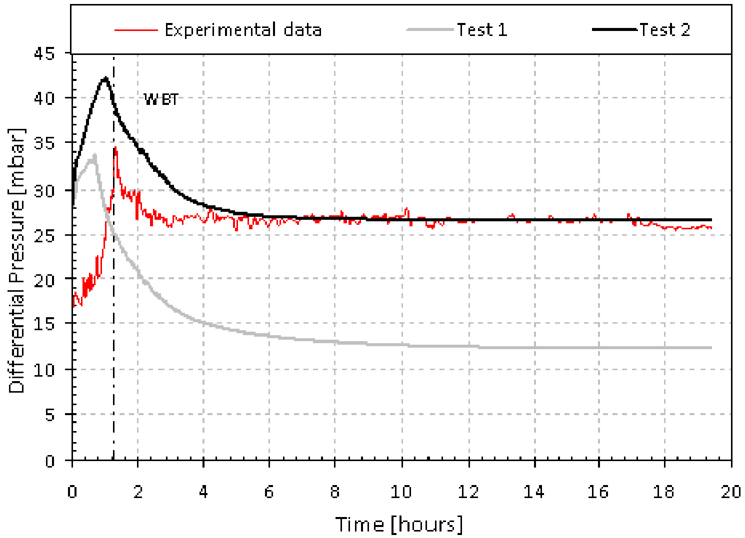


Sensitivity tests on the rel perm F_1 - factor

$$k_{ri} = F_1 k_{ri}^L + (1 - F_1) k_{ri}^H$$







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:

Alagic and Skauge (CIPR): "Change to Low Salinity Brine Injection in Combination with Surfactant Flooding," presented at 15th European Symposium on Improved Oil Recovery — Paris, France, 27 – 29 April 2009

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

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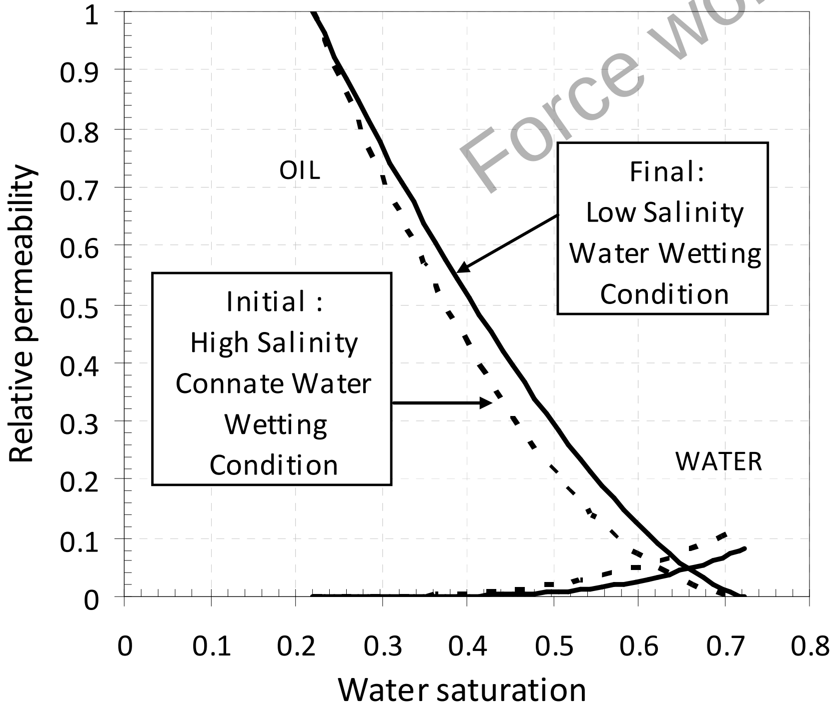
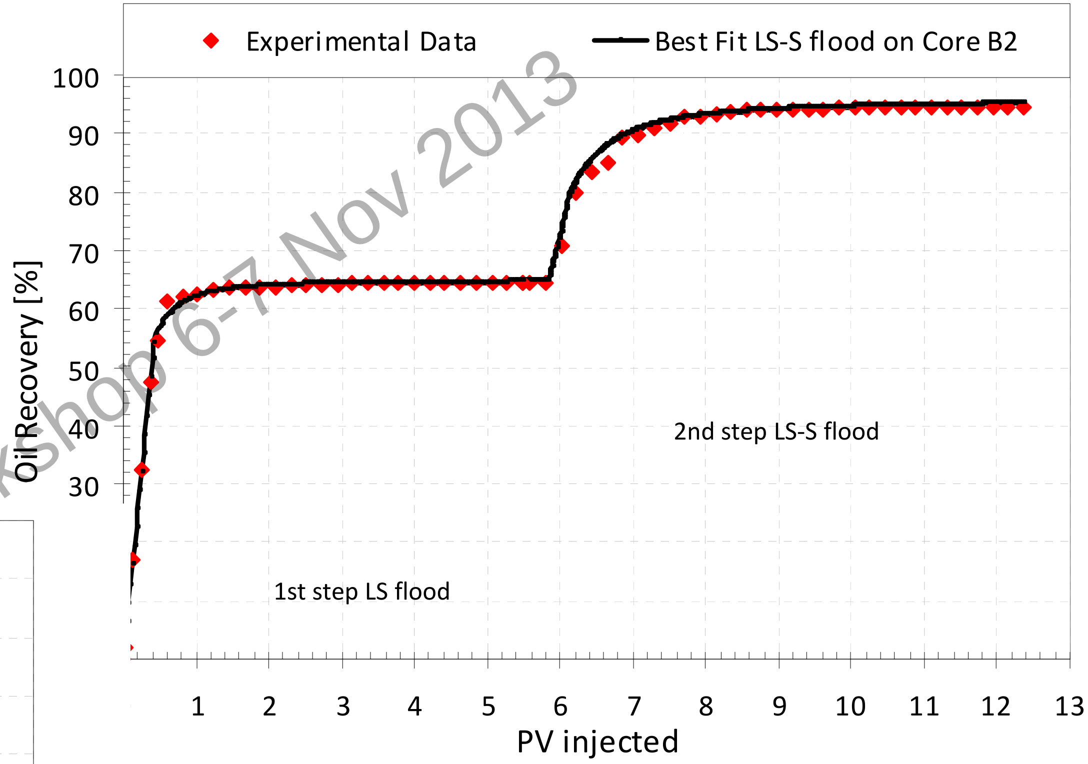
UTCHEM Simulations: LS flood → LS surfactant flood





Good simulation match of production data

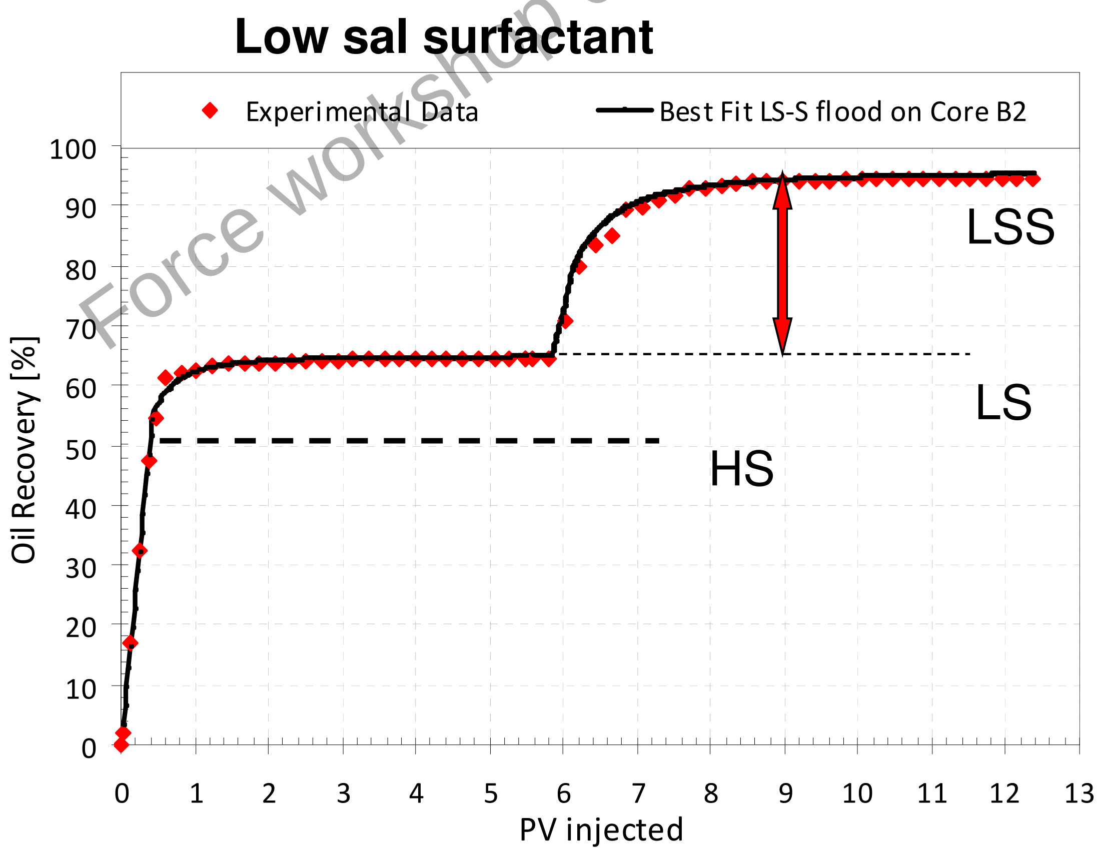
Skauge, A., Ghorbani, Z., and Delshad, M., Simulation of Combined Low Salinity Brine and Surfactant Flooding, (Sub ID: 9874), the EAGE IOR Symposium 12th – 14th April 2011 in Cambridge, UK.

Advantage of the combined EOR methods

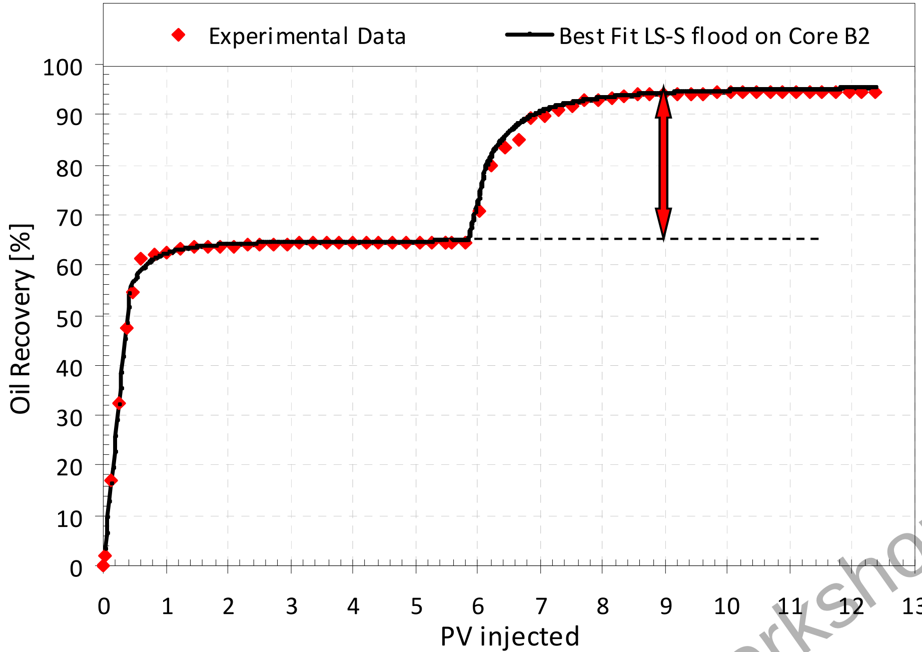
Low salinity reduces surfactant retention

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

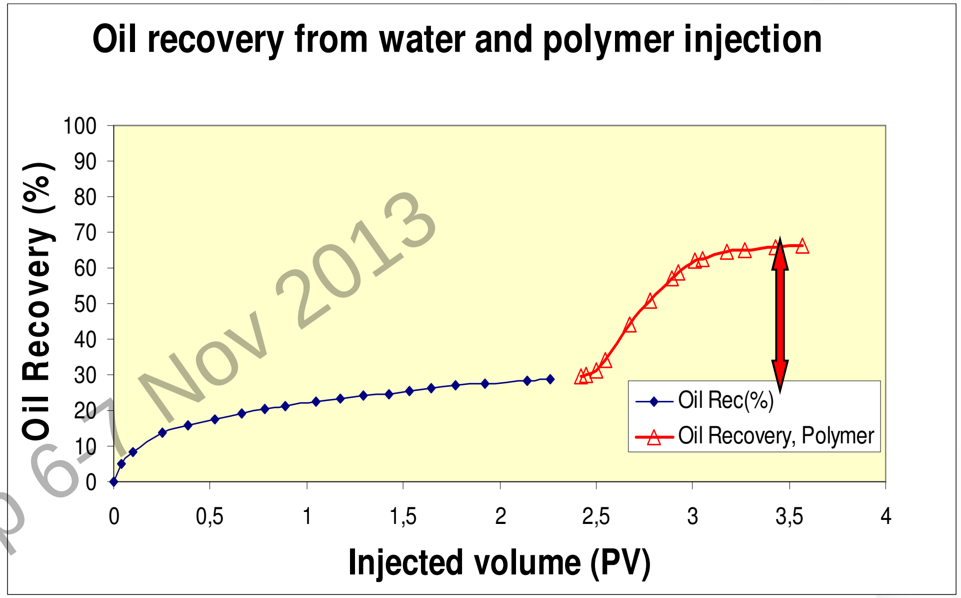
Low cost surfactants can be used at these salinities



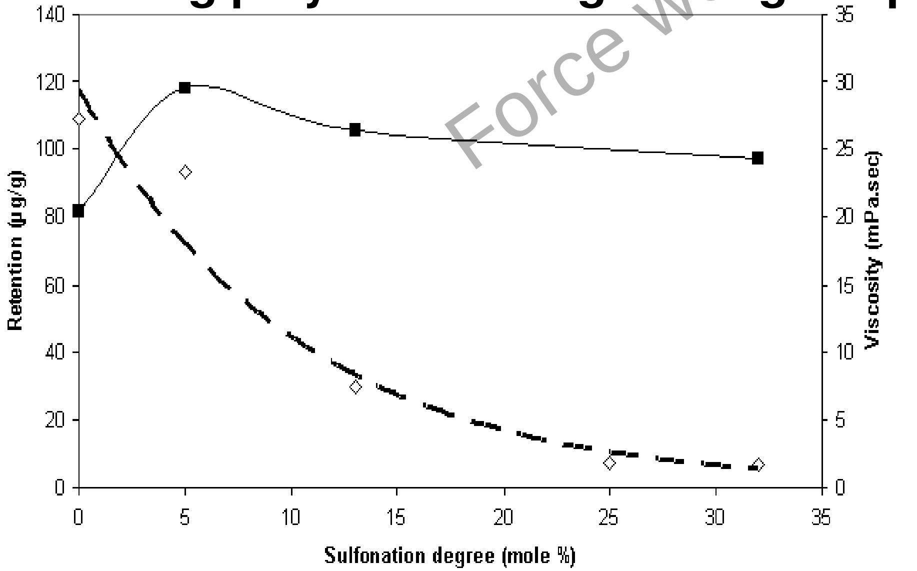
Low sal surfactant



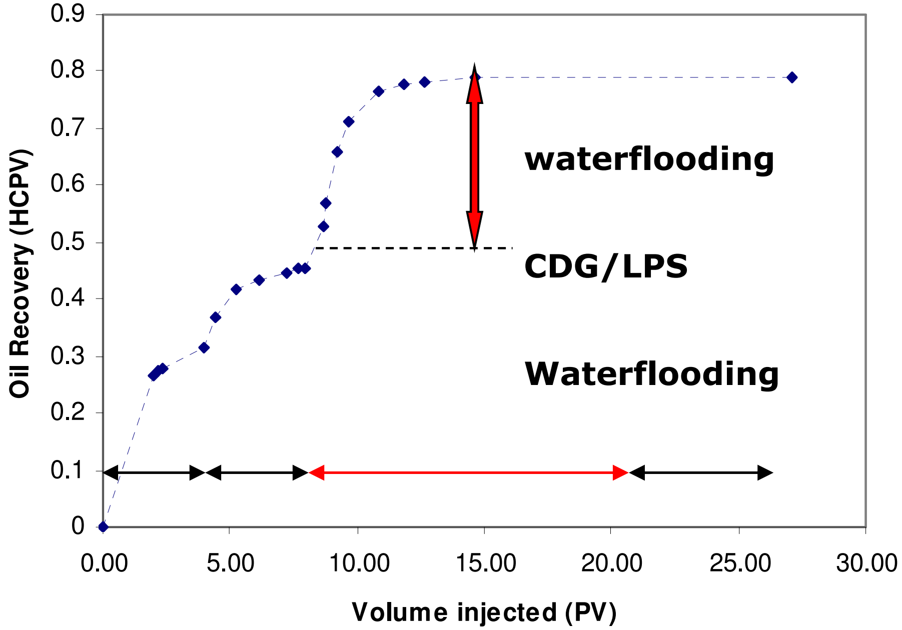
Polymer for heavy oil recovery



Extending polymers for high sal og temp



Nano polymer particles for EOR



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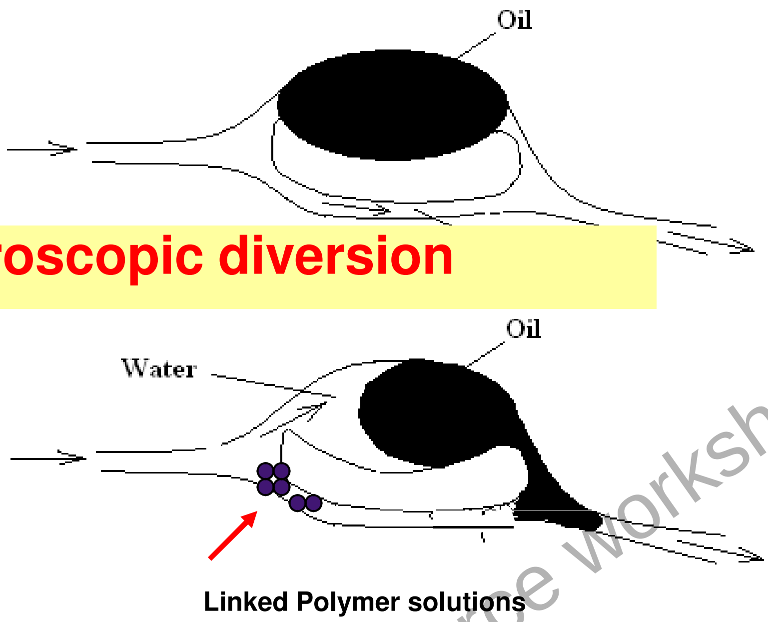
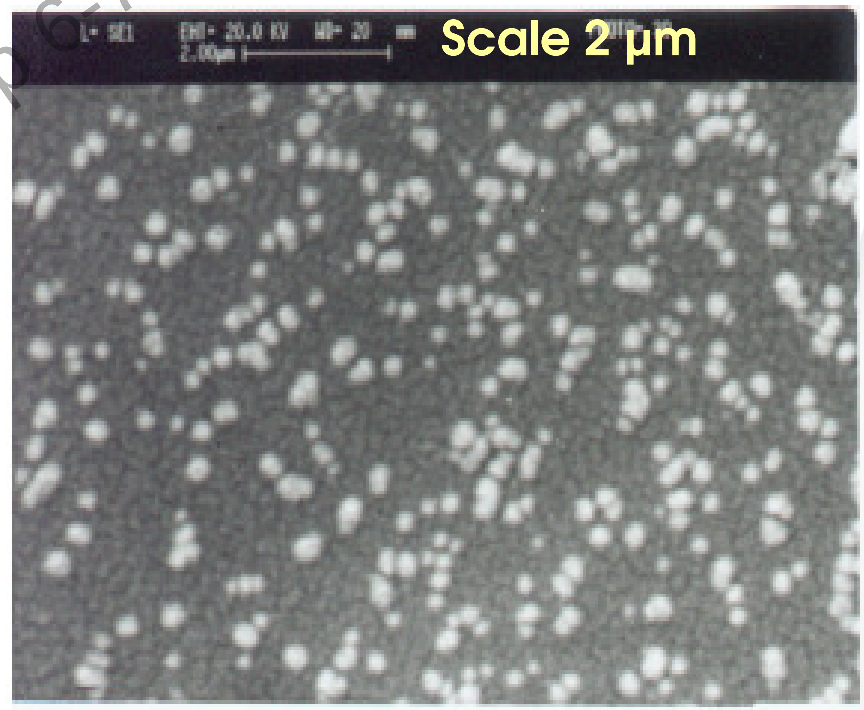
Nano particles mechanisms sweep improvement, but also..



SEM photograph of CDG particles



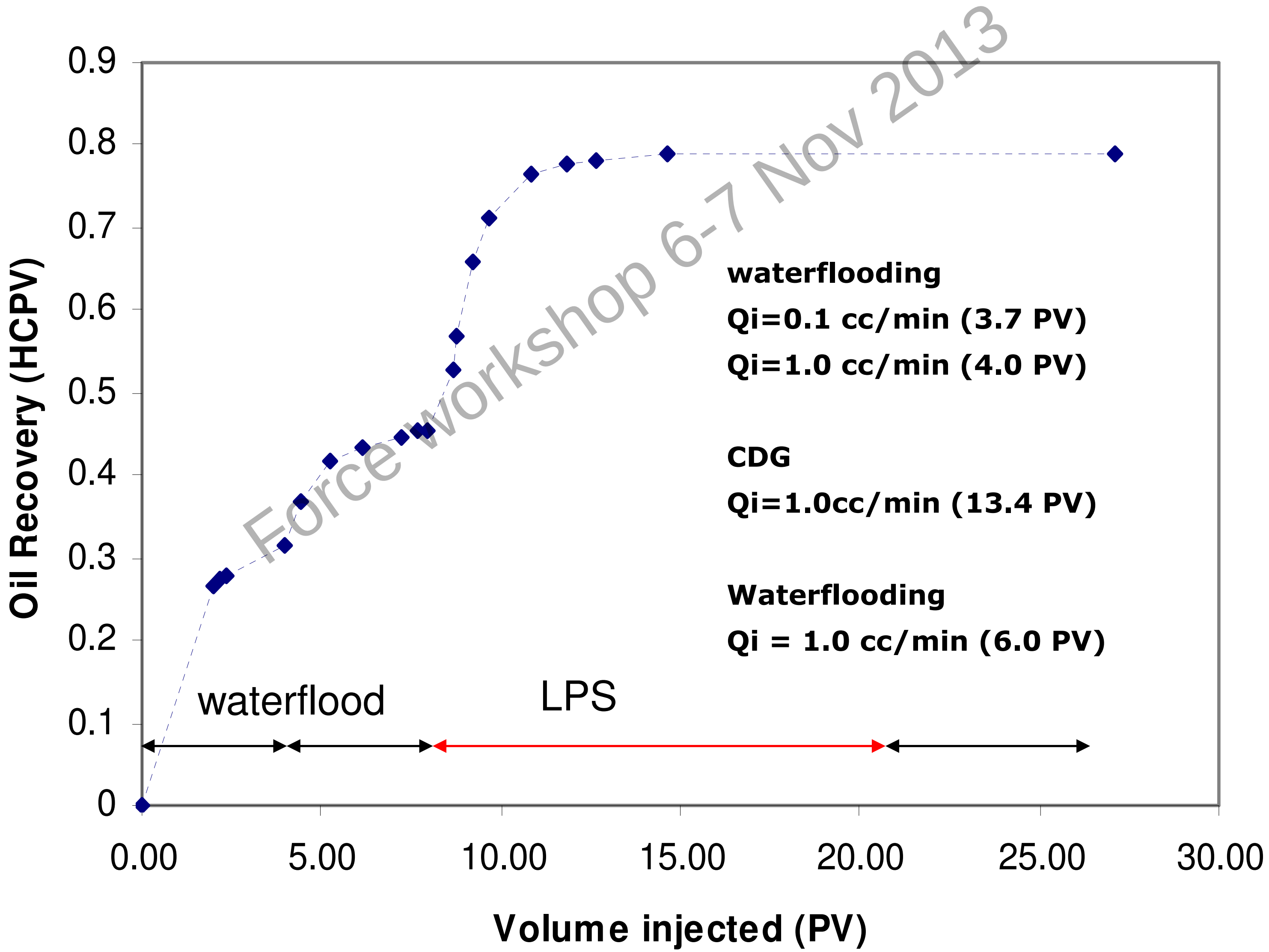
Spherical particles

Typical size 50-100 nm

Pre-generated particles;

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

LPS in core flood
Sandstone reservoir core (fresh core), K=900 mD



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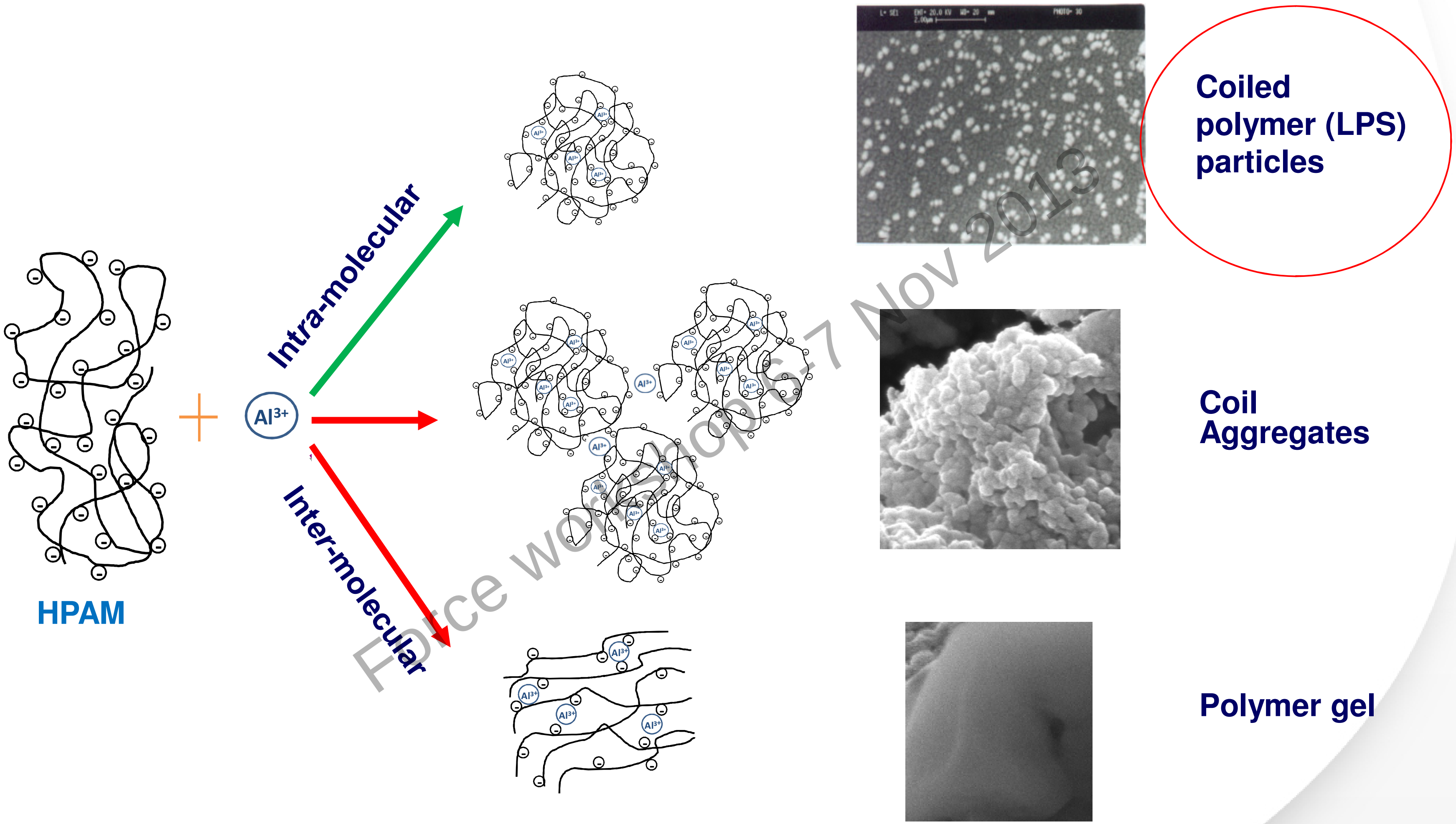
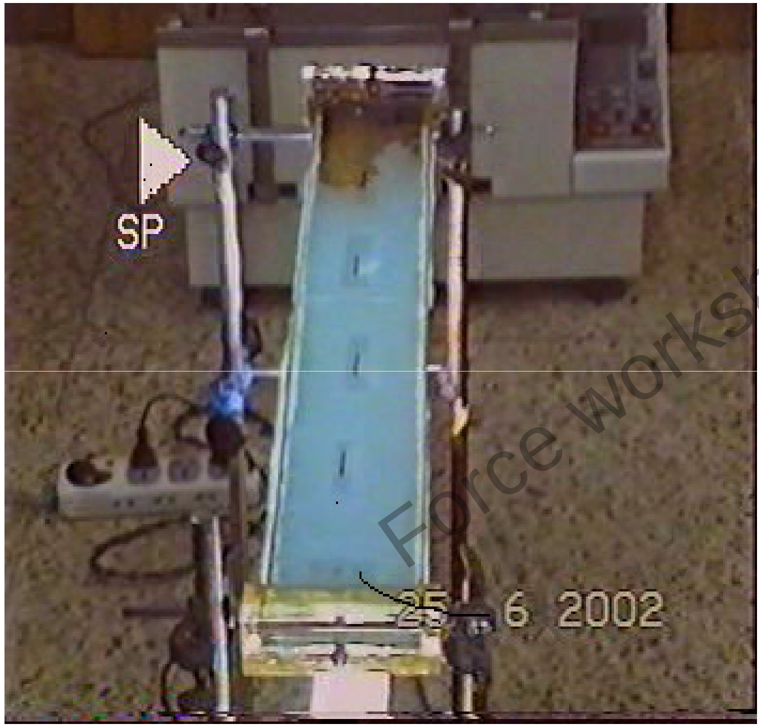
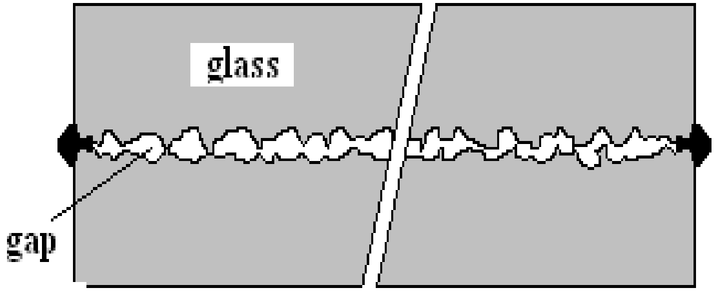


Intra-molecular aggregate is preferred

LPS flooding in a glass model



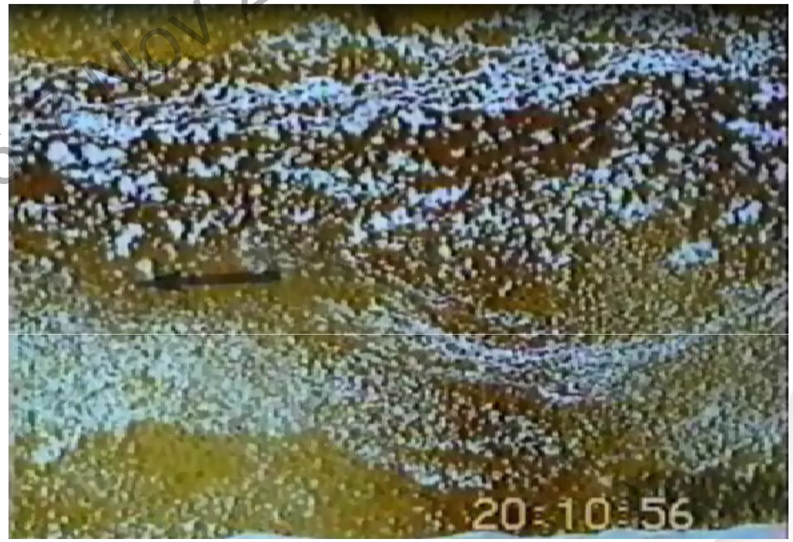
Heterogeneous etched pores on glass plates



L: 625 mm W: 100 mm Gap: 50-100 μm

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

Waterflooding at adverse mobility ratio



After LPS injection water is contacting
Initially bypassed pores

Way forward

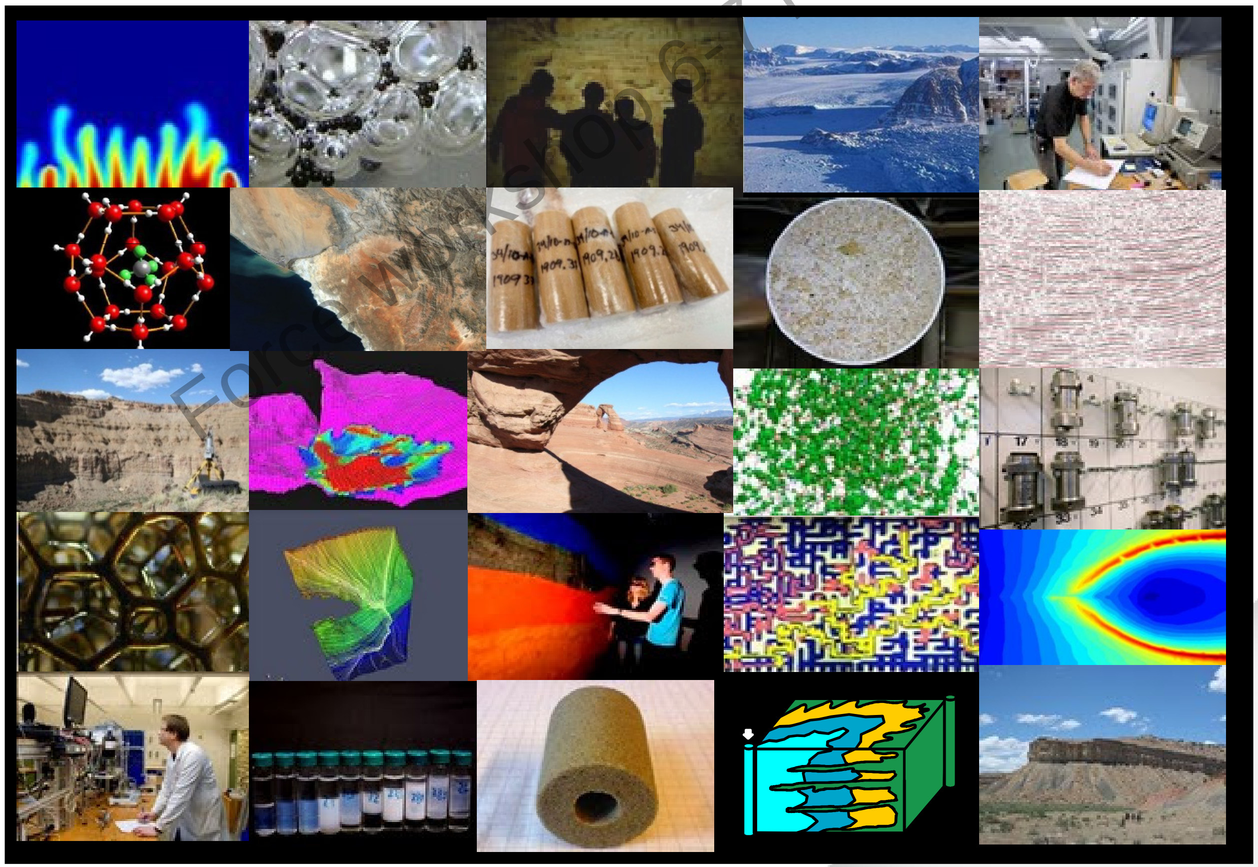
We will see more advanced flood sequences…

- 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



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