# Scaling, Asphaltenes, near-wellbore damage and how to study

# Scales – organic and inorganic

- What is scale and scaling?
- What does scale look like in the reservoir?
- Inorganic scaling prediction
- Inorganic inhibition
- Organic scales (asphaltenes)

# What is scale?

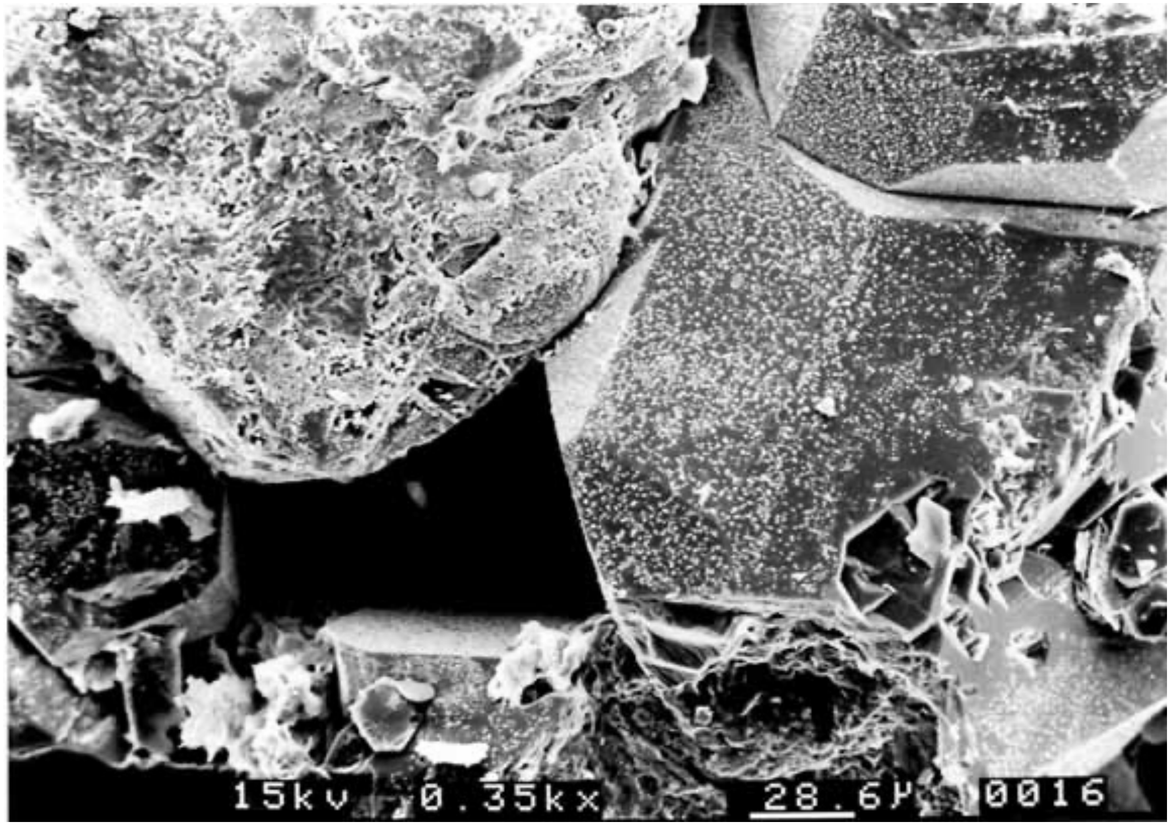
**Inorganic**:

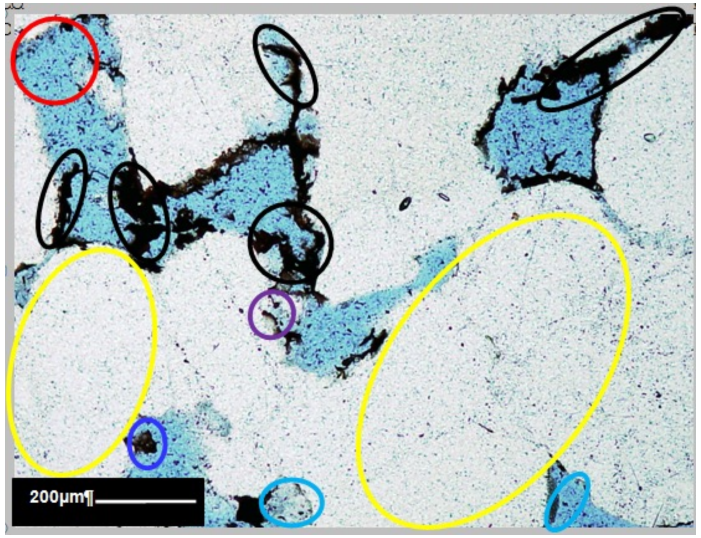
- From formation brine, introduced water, or both
- Salt deposit, with precipitation caused by chemical reactions (incompatibility), change in conditions (temperature, pressure, pH), fluid composition, reaction with surfaces
- So can occur throughout the life cycle, production & injection

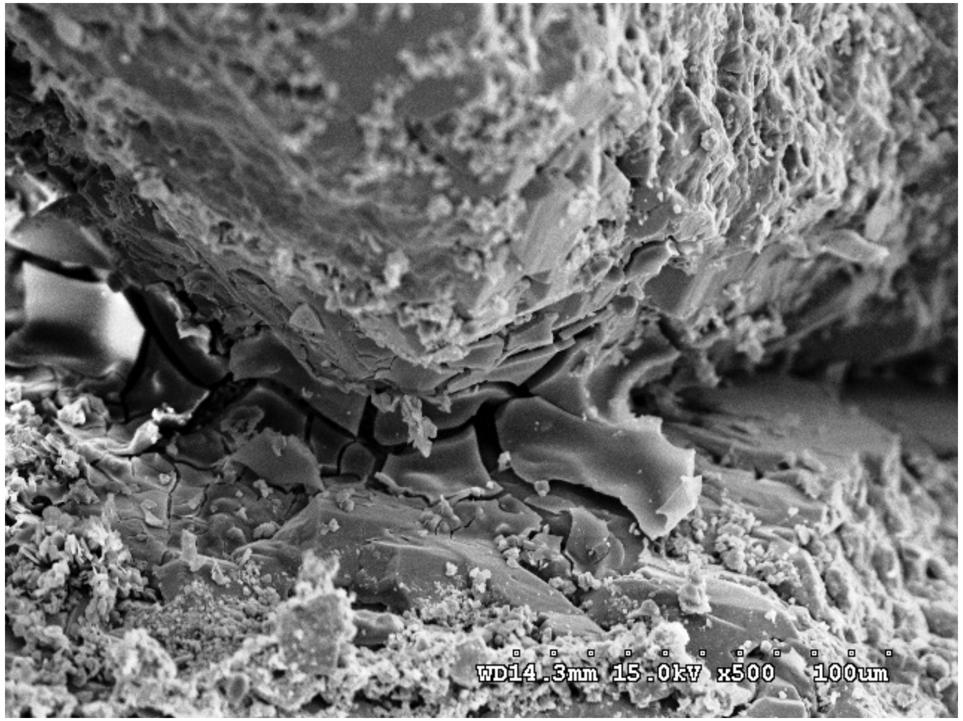
**Organic (asphaltenes)**:

- From hydrocarbon
- Solid portion (colloidal) of hydrocarbons, precipitated by saturates and dissolved by aromatics. Precipitation caused by change of conditions (bubble point), changes in chemistry, shear, acids
- So not just a production problem

# What they look like



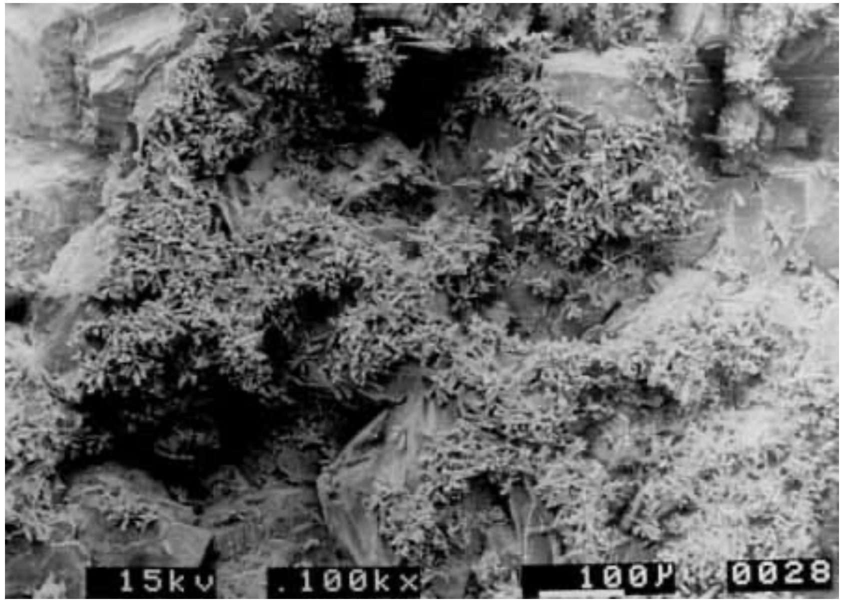



# Inorganic scaling: understanding

3 stages:

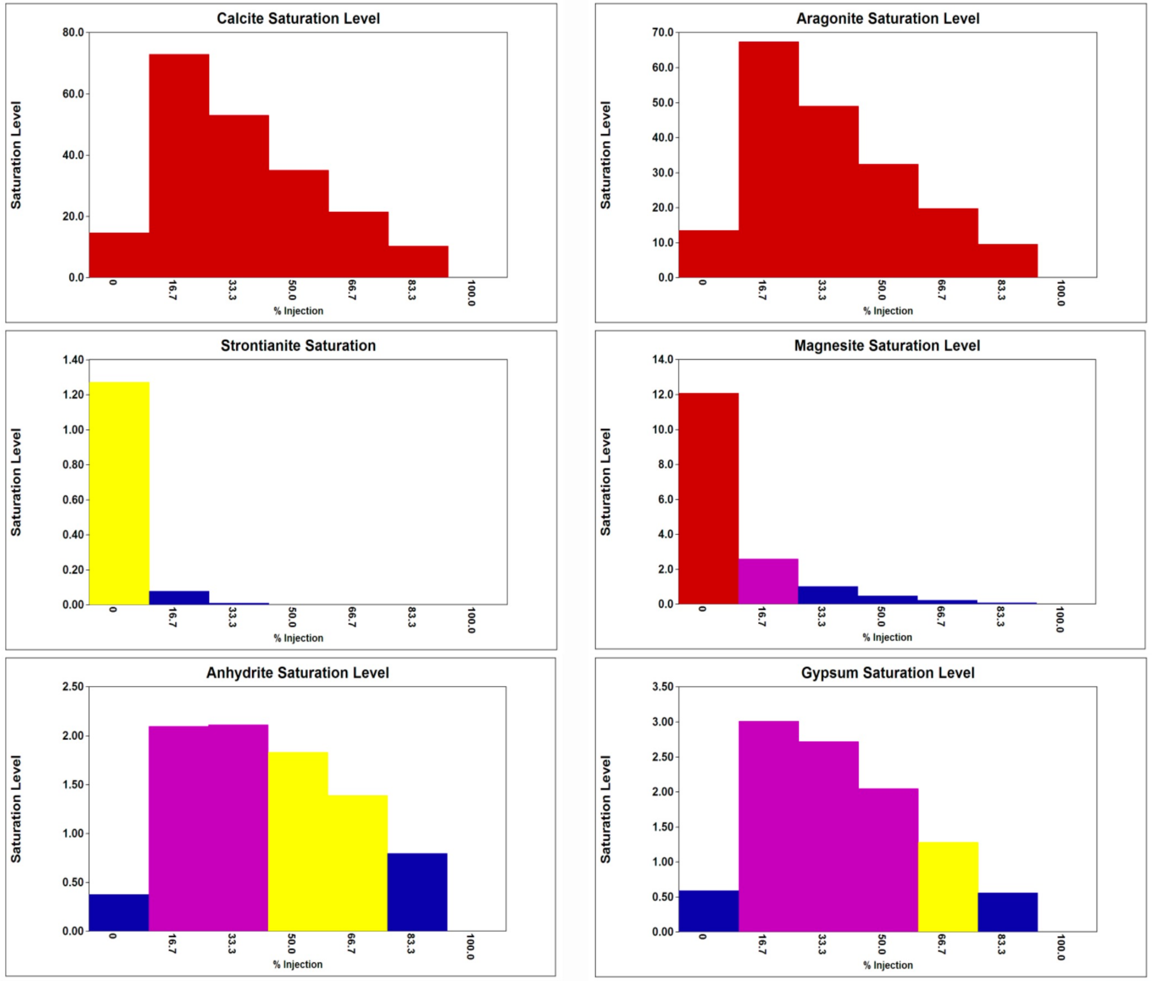
- Prediction: does it happen, what sort of scale are we seeing?
- Mitigation: what inhibitors can help with the problem?
- Evaluation: do the inhibitors work, do they have any side-effects?

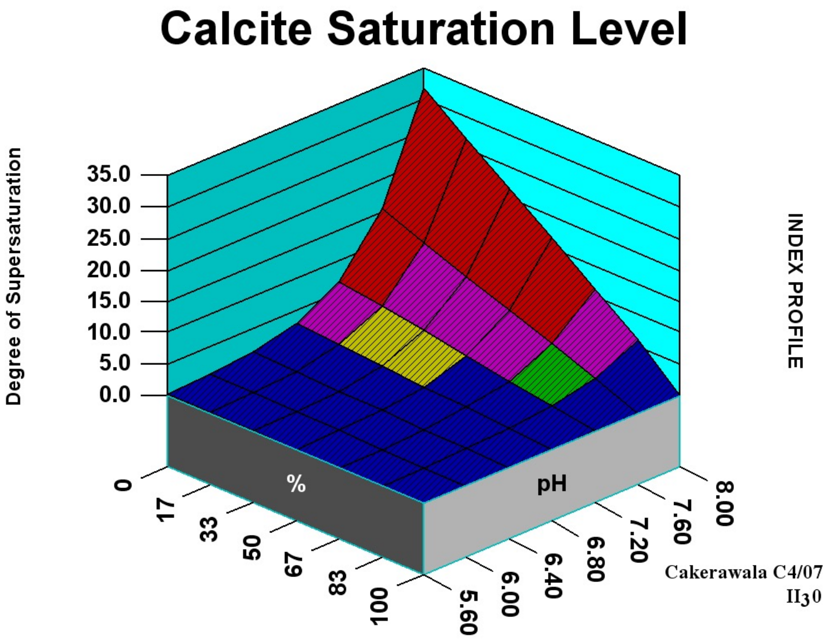


# Scale prediction modelling

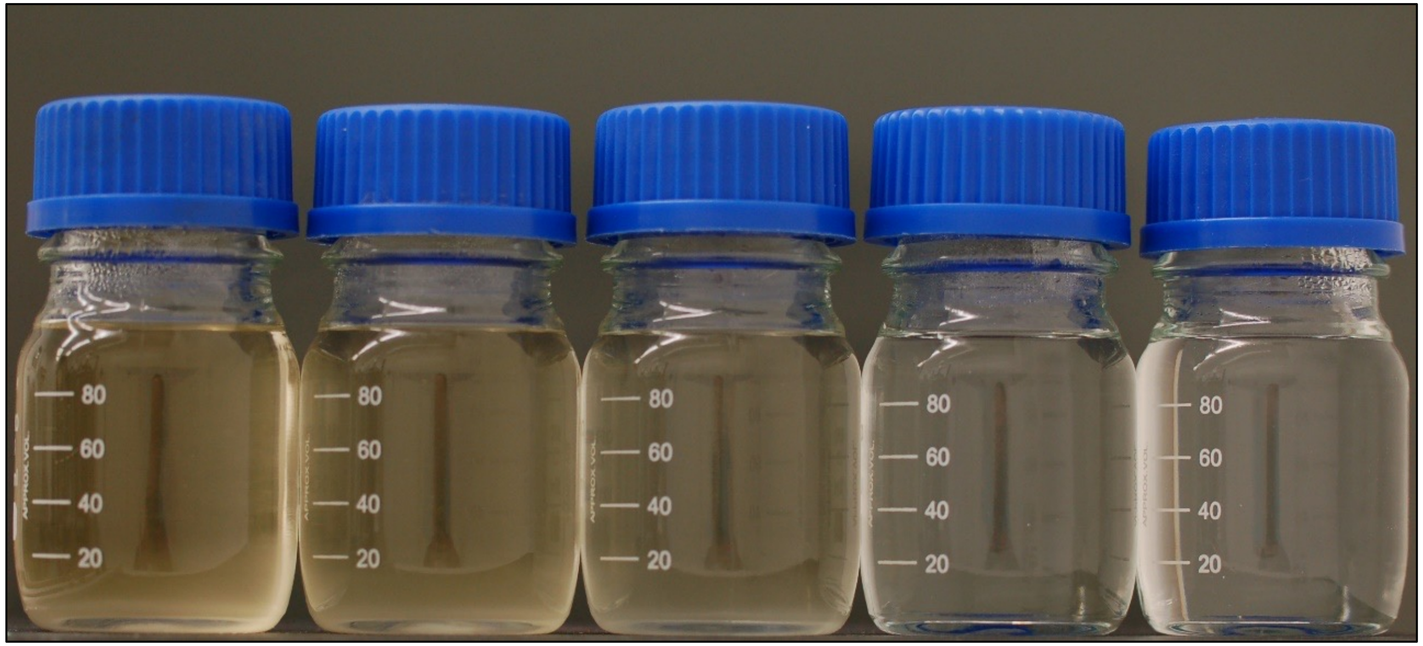
| Scaling Index (Saturation Level) | | % Completion Fluid 0 | 16.67 | 33.33 | 50 | 66.67 | 83.33 | 100 |
|---|---|---|---|---|---|---|---|---|
| Calcite | $CaCO_3$ | 28.63 | 17.26 | 11.54 | 6.67 | 41.89 | 0 | 0 |
| Aragonite | $CaCO_3$ | 31.09 | 18.74 | 12.53 | 7.24 | 45.48 | 0 | 0 |
| Witherite | $BaCO_3$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Strontianite | $SrCO_3$ | 2.1 | 0.535 | 0.132 | 0.0173 | 0.00144 | 0 | 0 |
| Magnesite | $MgCO_3$ | 113.07 | 86.97 | 68.98 | 44.76 | 107.03 | 0 | 0 |
| Anhydrite | $CaSO_4$ | 1.59 | 0.772 | 0.987 | 1.8 | 6.94 | 0 | 0 |
| Gypsum | $CaSO_4*2H_2O$ | 0.43 | 0.179 | 0.184 | 0.231 | 0.111 | 0 | 0 |
| Barite | $BaSO_4$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Celestite | $SrSO_4$ | 0.321 | 0.066 | 0.0311 | 0.0129 | <0.001 | 0 | 0 |
| Tricalcium phosphate | $Ca_3(PO_4)_2$ | 0.406 | 0.17 | 0.263 | 1.11 | 565.57 | 0 | 0 |
| Hydroxyapatite | $Ca_5(PO_4)_3(OH)$ | 0.965 | 0.161 | 0.297 | 3.36 | 104135 | 0 | 0 |
| Fluorite | $CaF_2$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Silica | $SiO_2$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Brucite | $Mg(OH)_2$ | 4.29 | 2.1 | 2.25 | 4.38 | 11.94 | 0 | 0 |
| Magnesium silicate | $MgSiO_3$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ferric hydroxide | $Fe(OH)_3$ | 1170 | 360.48 | 146.86 | 61.36 | 4.18 | 0 | 0 |
| Siderite | $FeCO_3$ | 16.27 | 8.21 | 2.61 | 0.399 | 0.04 | 0 | 0 |
| Strengite | $FePO_4*2H_2O$ | 1.63 | 1.17 | 0.558 | 0.144 | 0.00144 | 0 | 0 |
| Halite | $NaCl$ | 0.00268 | 0 | 0 | 0 | 0 | 0 | 0 |
| Thenardite | $Na_2SO_4$ | <0.001 | <0.001 | <0.001 | <0.001 | <0.001 | 0 | 0 |
| Iron sulphide | $FeS$ | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

# Scale prediction modelling



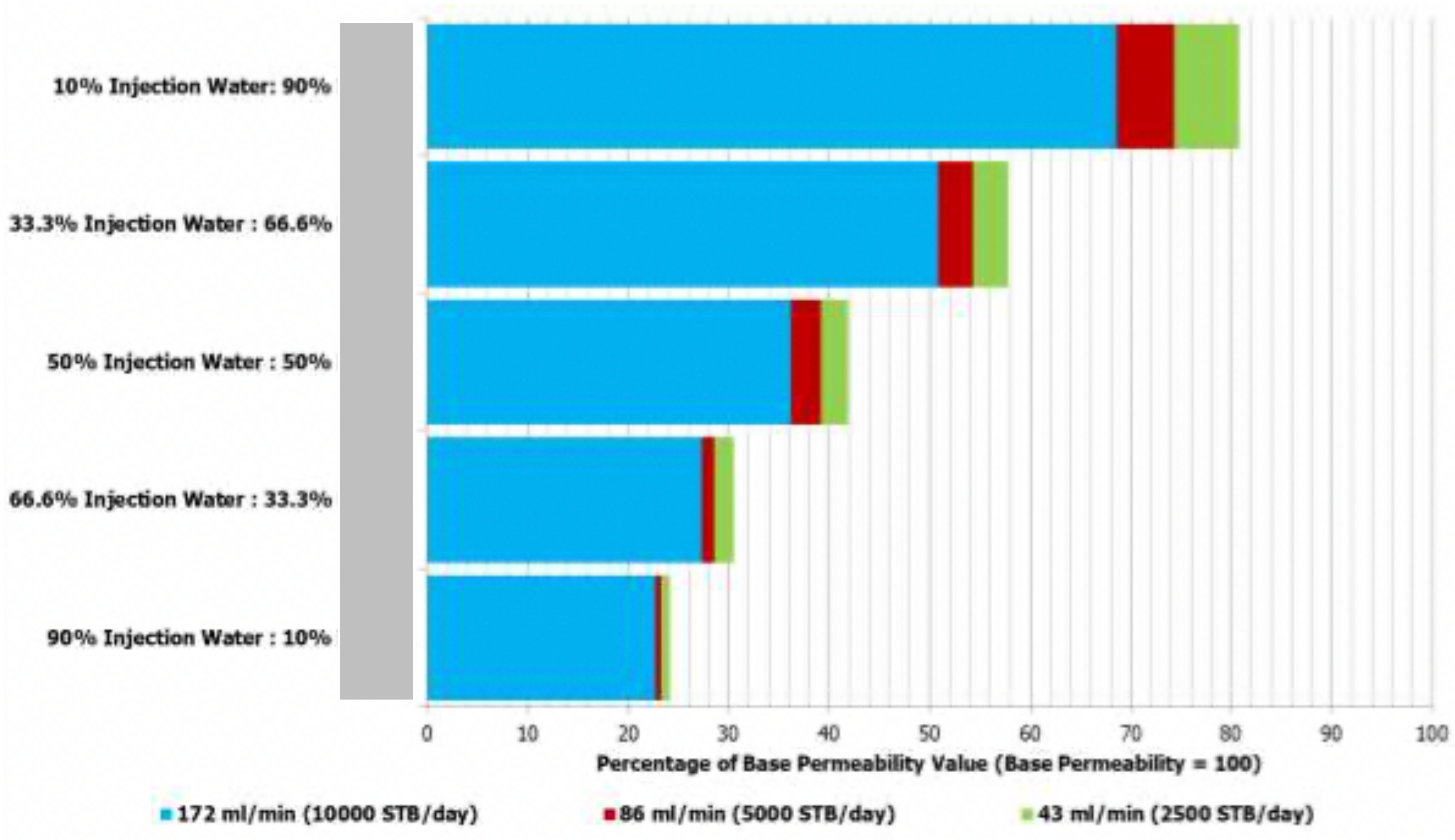



# Fluid compatibility incubation tests




Scale precipitate at left (90:10, 75:25, 50:50 water 1:water 2)

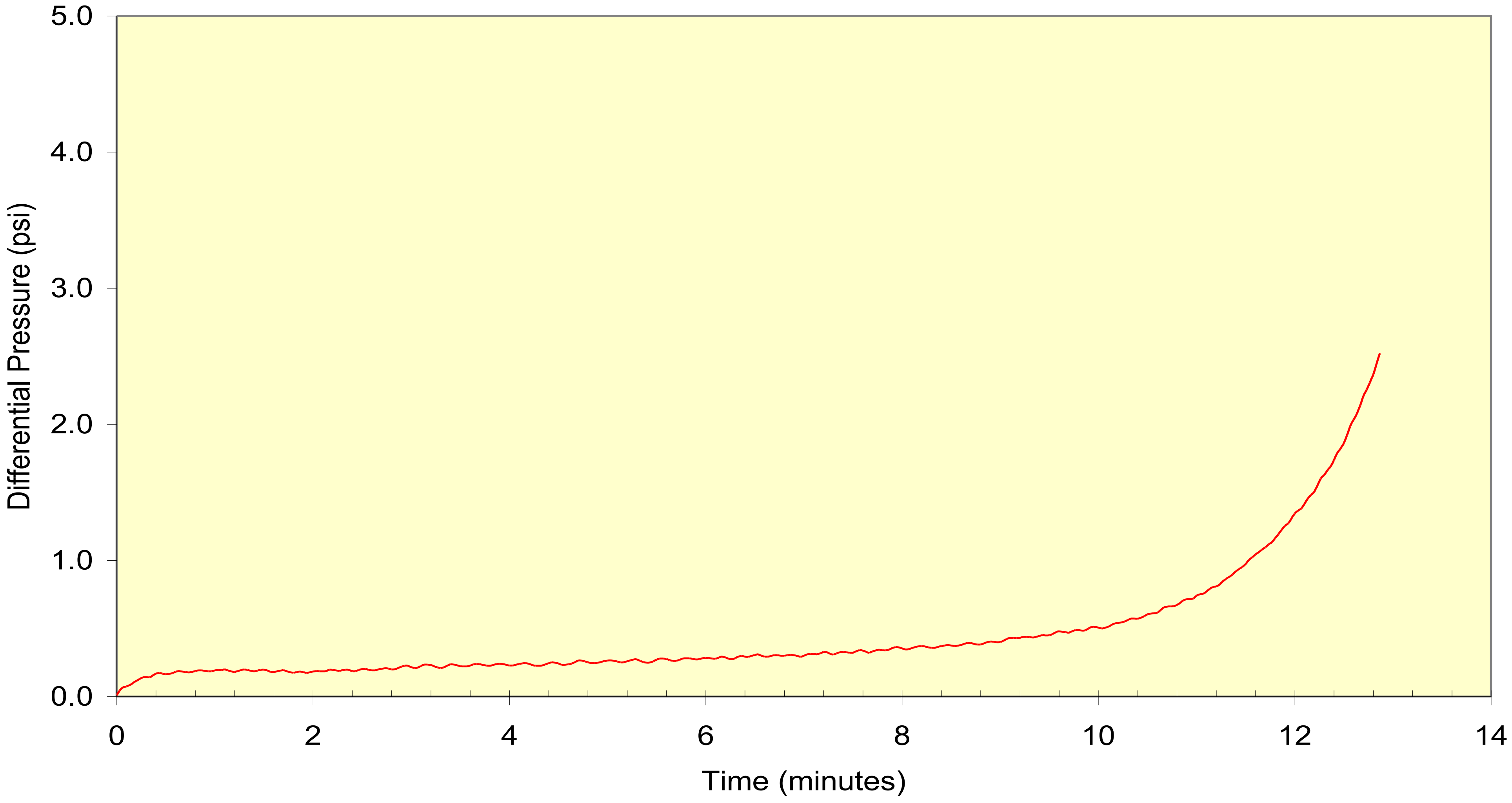
# Consider different mixes too!



# Scale inhibitor testing

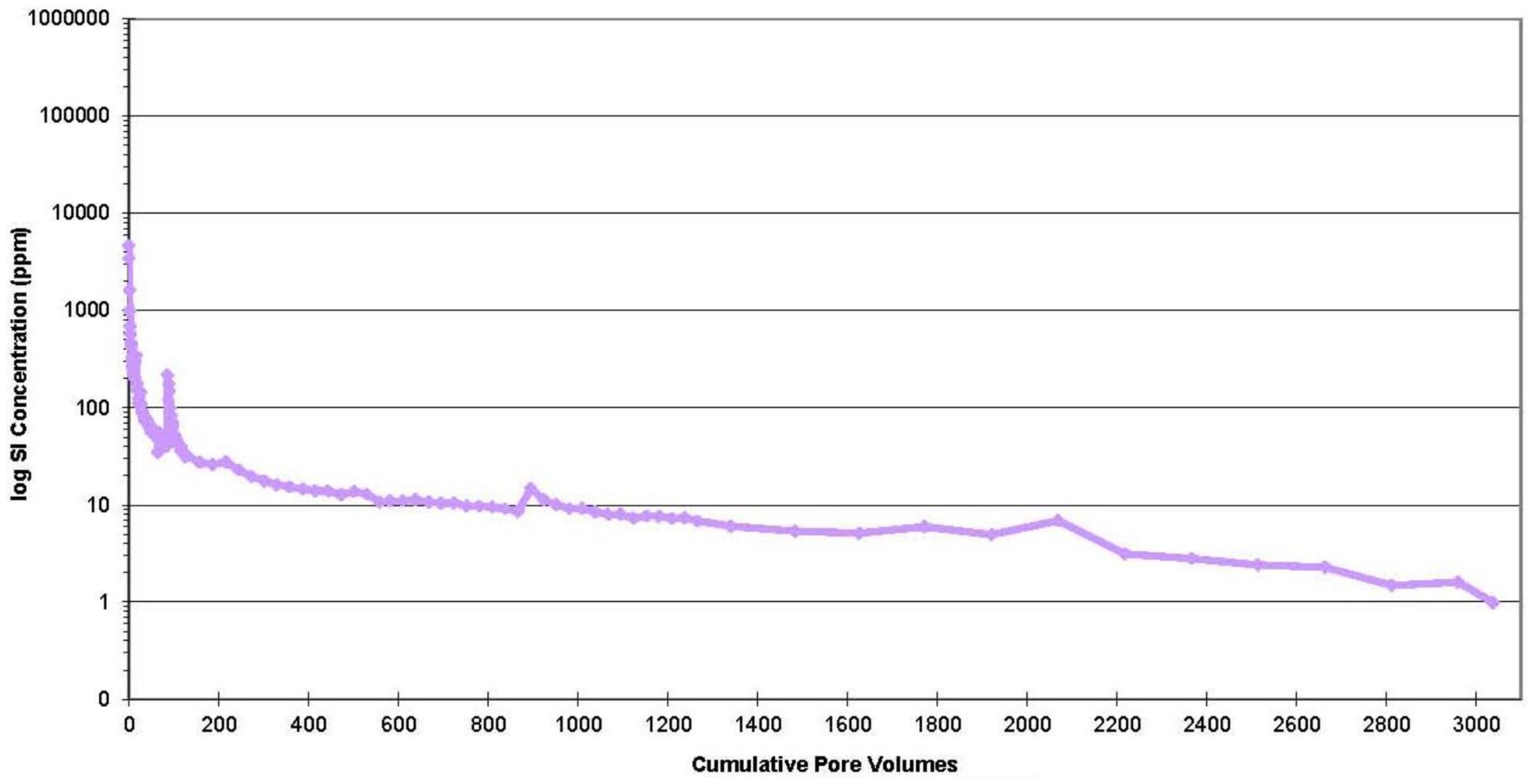
- Static jar tests and dynamic scale loop tests carried out to determine the efficiency of scale inhibitor chemicals
  - Static jar tests examine long residence times
  - Dynamic loop tests examine short residence times
  - Establishes the minimum inhibitor concentration (MIC)
- Coreflood simulations to examine proposed treatment fluids
  - Simulations to examine inhibitor return profile
  - Simulations to examine formation damage mechanisms

# Dynamic tube blocking



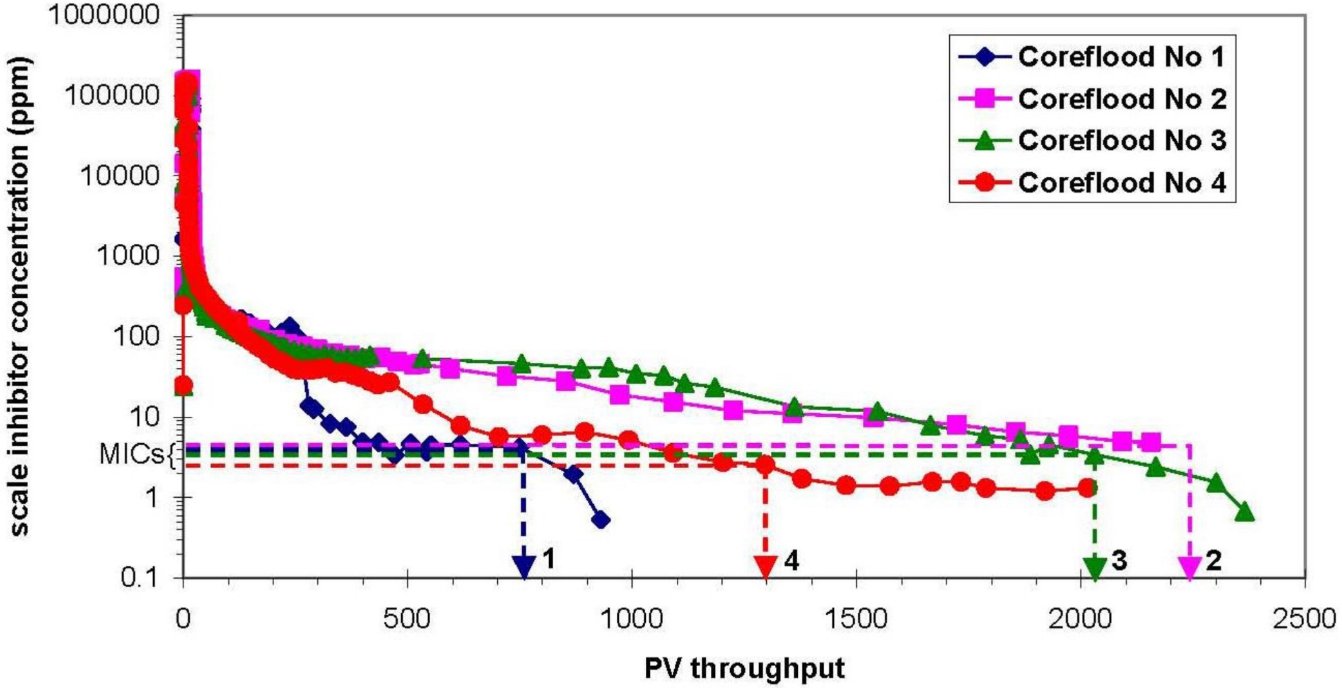
# Reservoir-conditions simulations

# Scale Inhibitor lifetime (desorption)

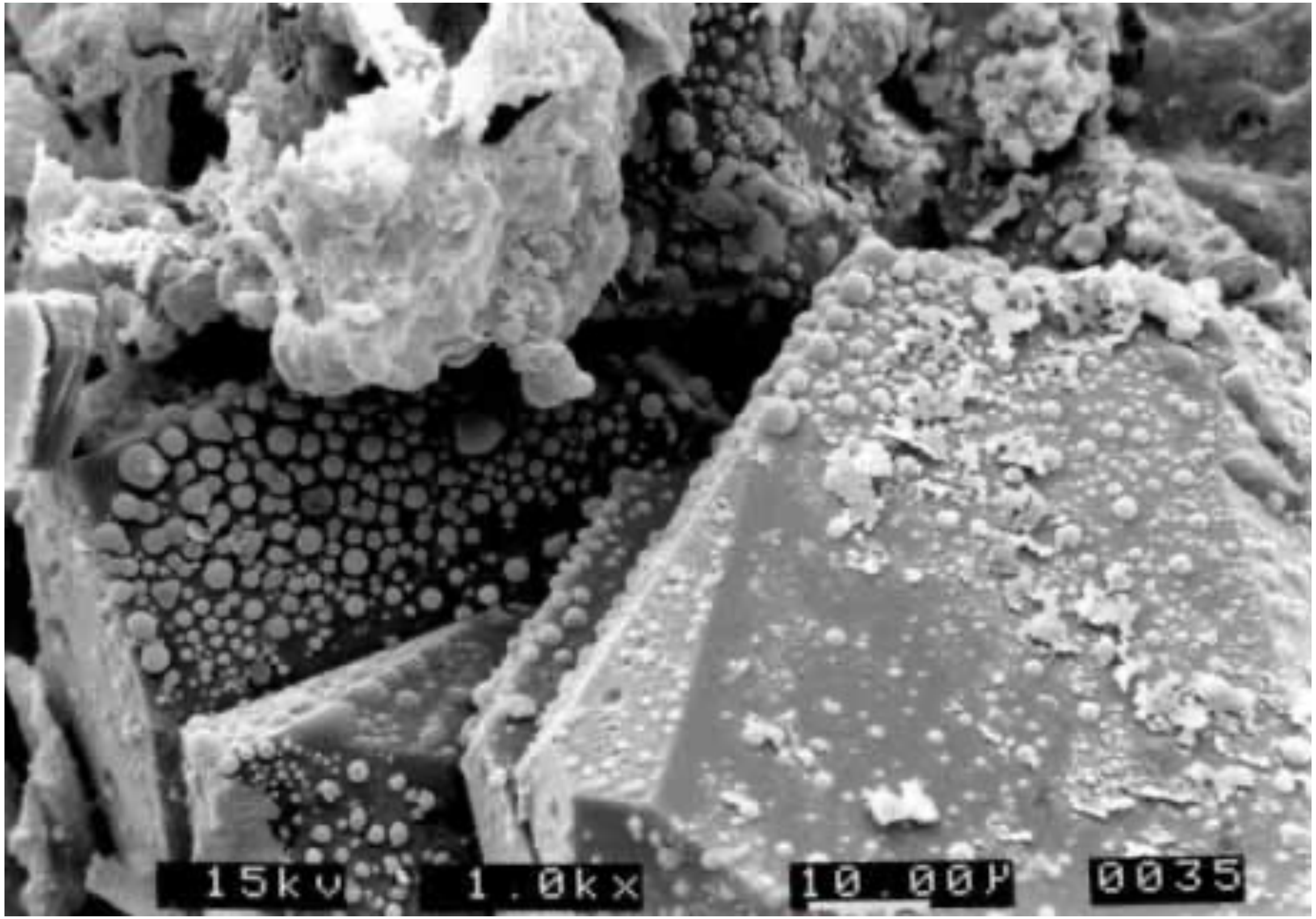


# Scale Inhibitor lifetime (desorption)

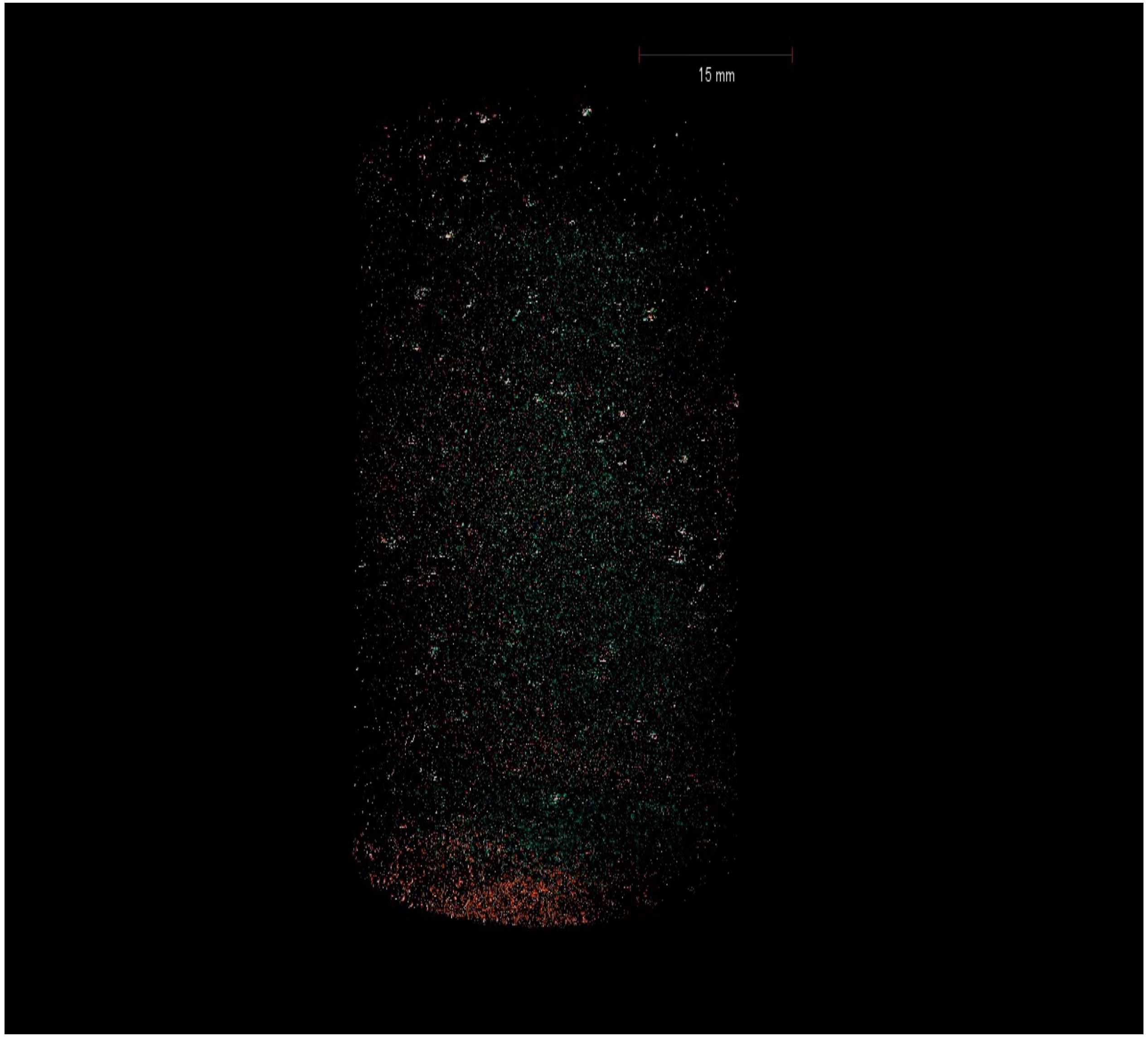
| Coreflood | Generic inhibitor type | Retention mechanism | MIC (ppm) | Throughput to reach MIC (PV) |
|---|---|---|---|---|
| No 1 | sulphonated co-polymer | precipitation | 4.7 | 750 |
| No 2 | phosphonated poly amine | adsorption | 4.8 | 2250 |
| No 3 | penta phosphonate | adsorption | 3.8 | 2020 |
| No 4 | penta phosphonate | precipitation | 2.8 | 1300 |
| *Test Conditions* | | | | |
| Temperature | 100 °C | Flow rate 60 ml/h | | |
| Confining pressure | 1000 psia | Shut-in 24 hrs | | |
| Initial saturation | Sor | | | |



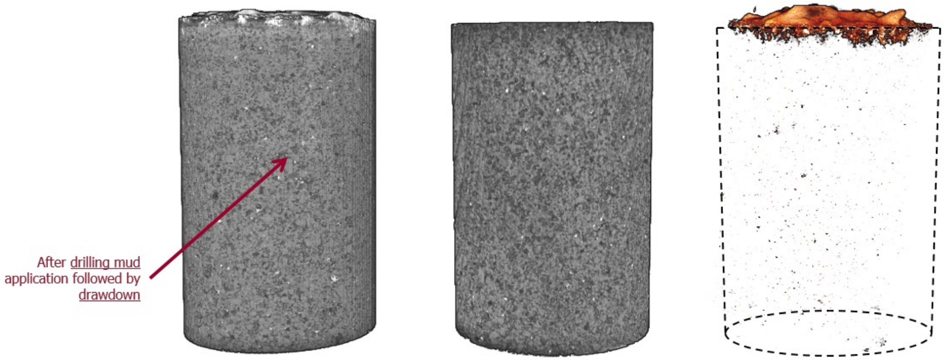
# Don’t forget inhibitor sequence compatibility!



# Formation Damage simulation studies

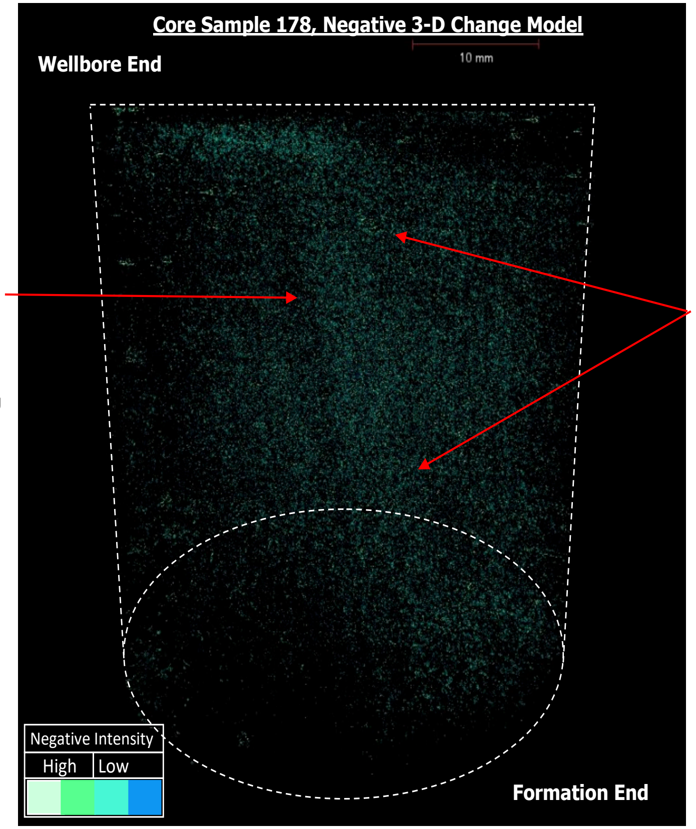



- Severe reduction in permeability (c60%)
- What caused that alteration?



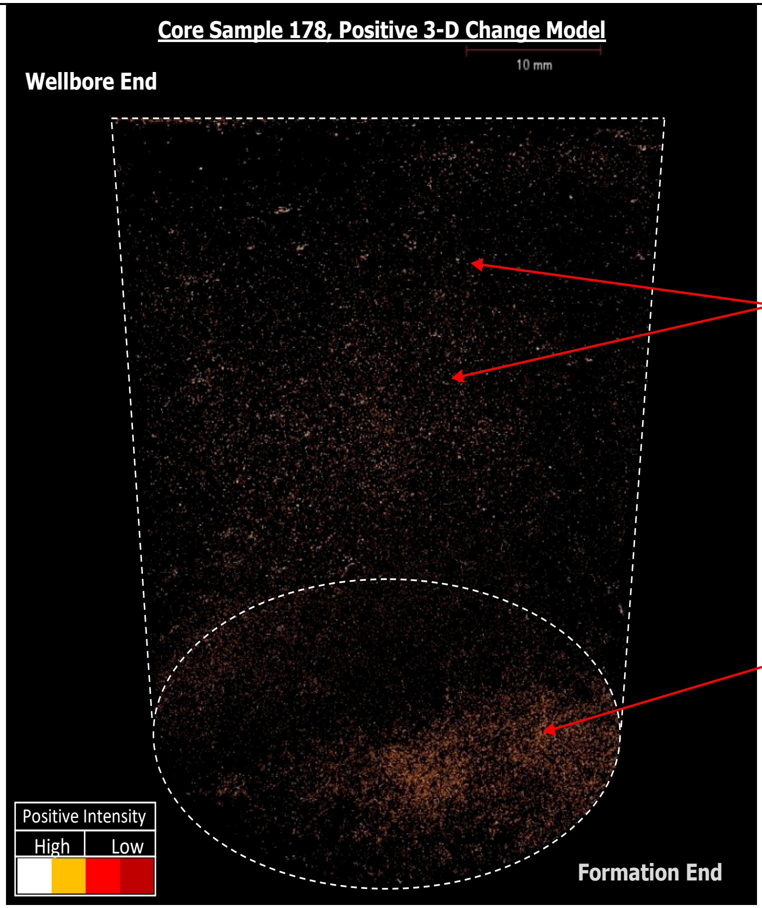
# New visualisation techniques show us more

A minor amount of change along bedding feature possibly caused by authigenic cementation or a high concentration of pore-filling and pore-lining clay minerals restricting flow in this region.




Moderate amounts of high intensity change along the length of the core sample caused by changes in density, possibly due to removal of fines.

*Fig 2: Negative 3-D 'change model' of the high intensity features scattered throughout core sample 178. A white border has been included around the edges of the core sample for depiction purposes only.*

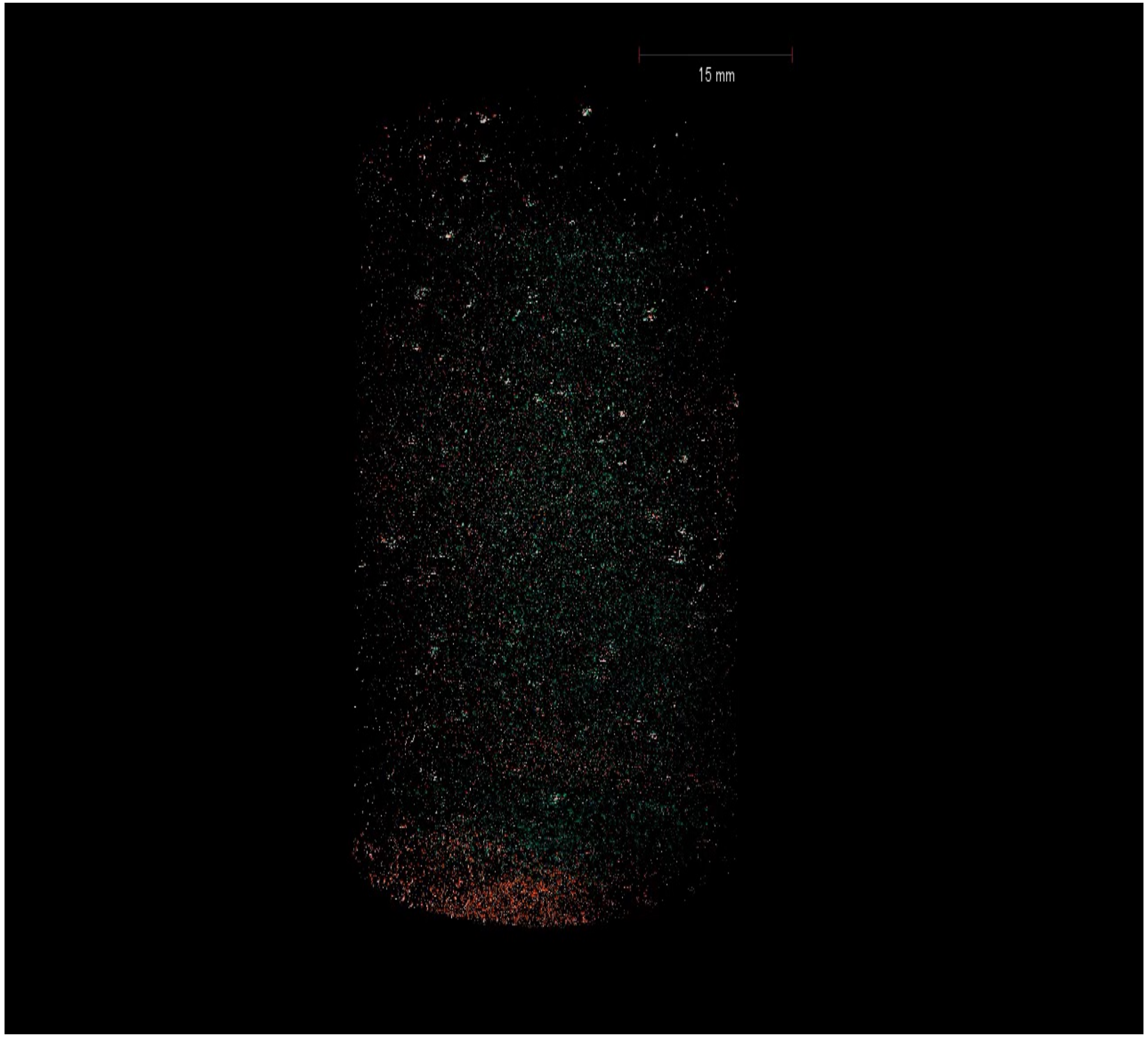



A moderate amount of high intensity change along the length of the core sample caused by changes in density, possibly due to accumulation of fines and/or fluid retention.

An abundant amount of high intensity change at the formation end of the core sample caused by changes in density, possibly due to accumulation of re-distributed/back-produced fines and/or fluid retention.

*Fig 3: Positive 3-D 'change model' of the high intensity features scattered throughout core sample 178. A white*

# Formation Damage simulation studies



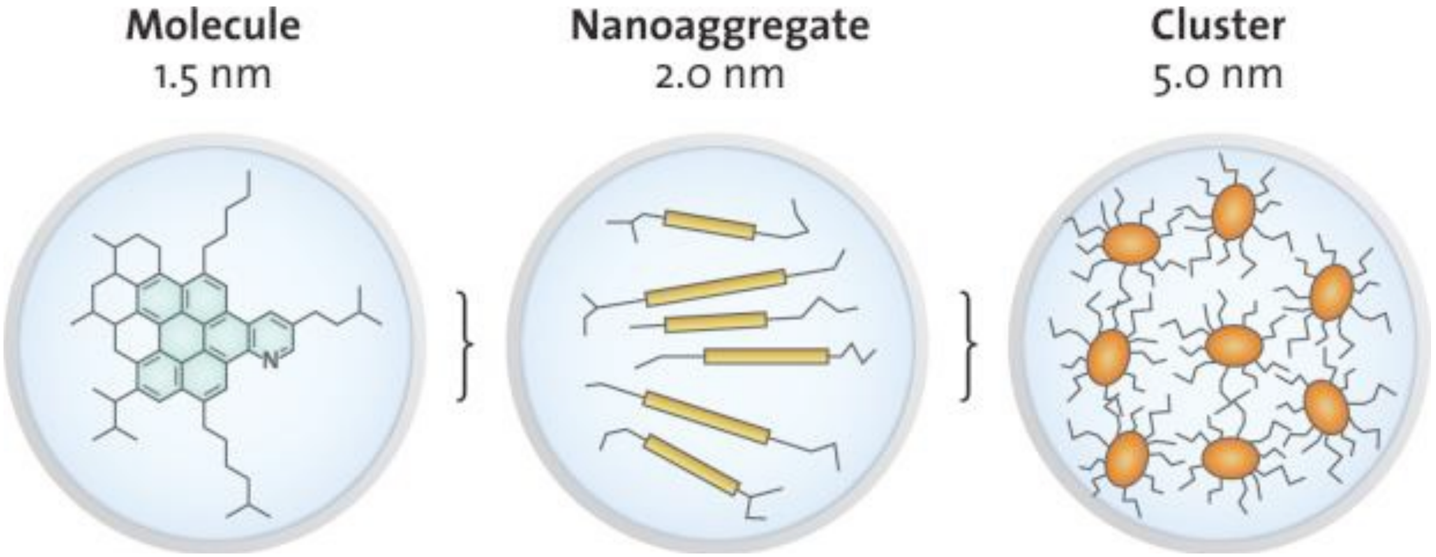

- Combination of changes = severe reduction in permeability (c60%)
- Clay: some removal, some accumulation
- Inhibitor: fluid retention, particularly associated with clay minerals
- Overall: reduction in pore volume
- Result: suitable chemical?

# Summary: inorganic scale studies

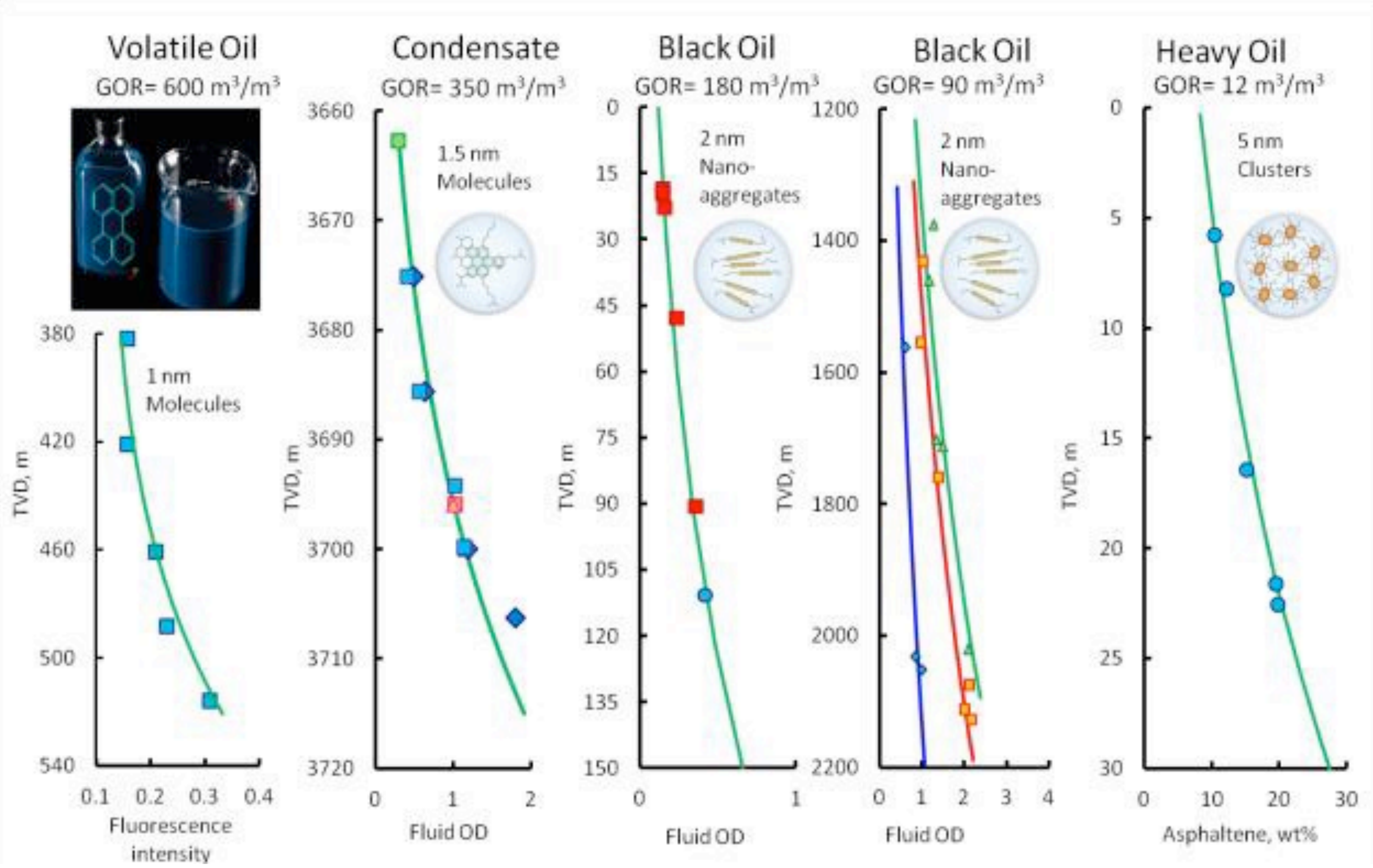
- Scale prediction modelling (computer simulations)
- Static fluid compatibility (jar) tests
- Modelling of candidate inhibitor types
- Selection of inhibitor (vendor)
- Repeat fluid compatibility with candidate inhibitors
- Dynamic tube blocking
- Coreflood studies for squeeze efficacy/lifetime
- Coreflood studies for scale inhibitor compatibility

# Organic precipiates: asphaltenes

- Asphaltene chemistry is complex and depends on a number of factors:
  - Gravity, GOR, fluid density, HC composition, etc.
- Asphaltenes exists as three major structural forms (Yen-Mullins model)
  - Molecular
  - Nanoaggregate
  - Clusters

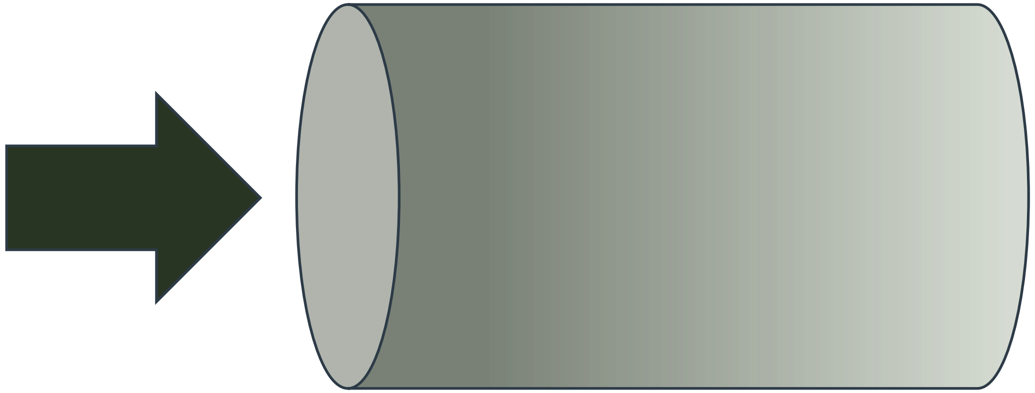
# General asphaltene correlation to oil grade



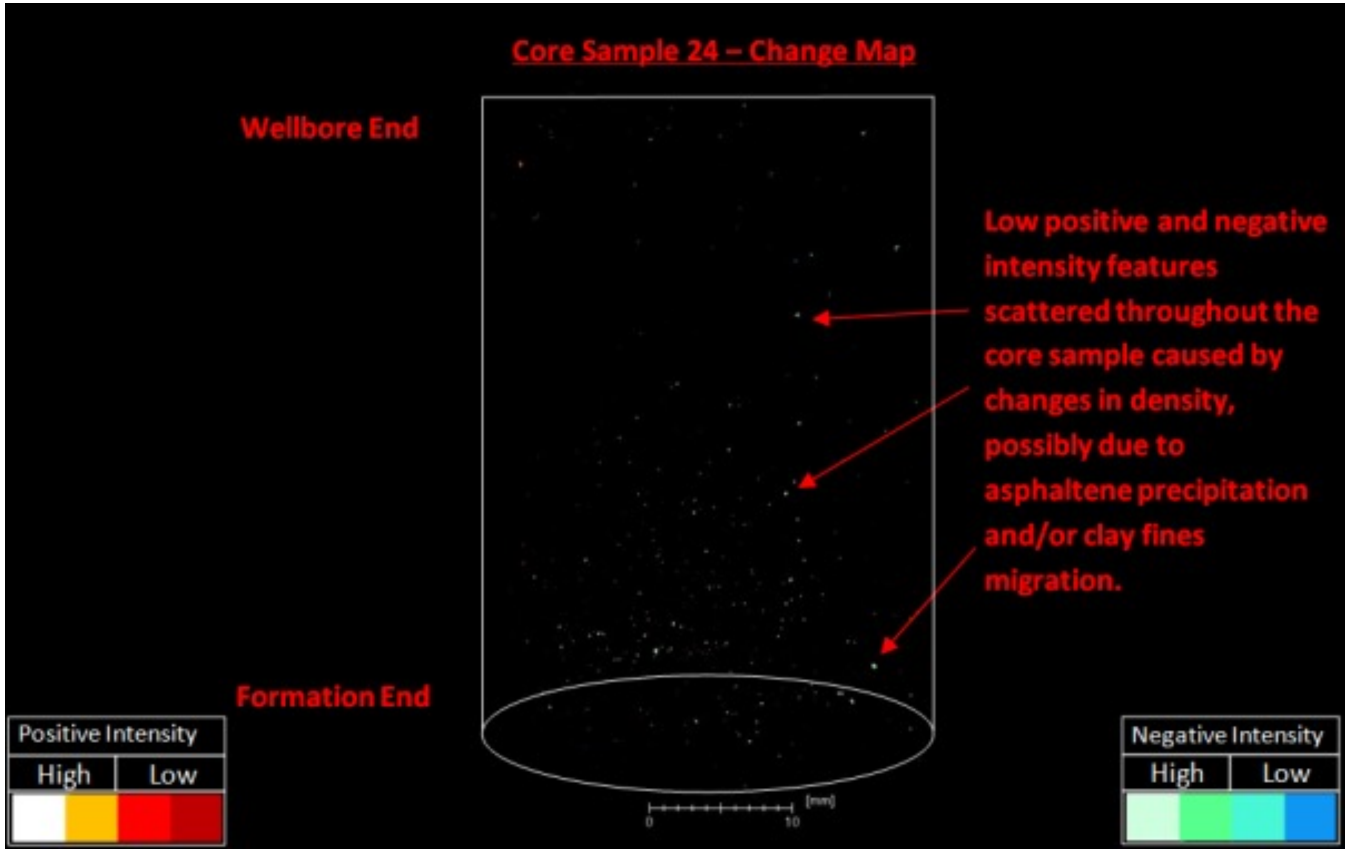

- Larger asphaltene structures tend to exhibit greater instability
- So heavy oil greatest risk but many factors contribute

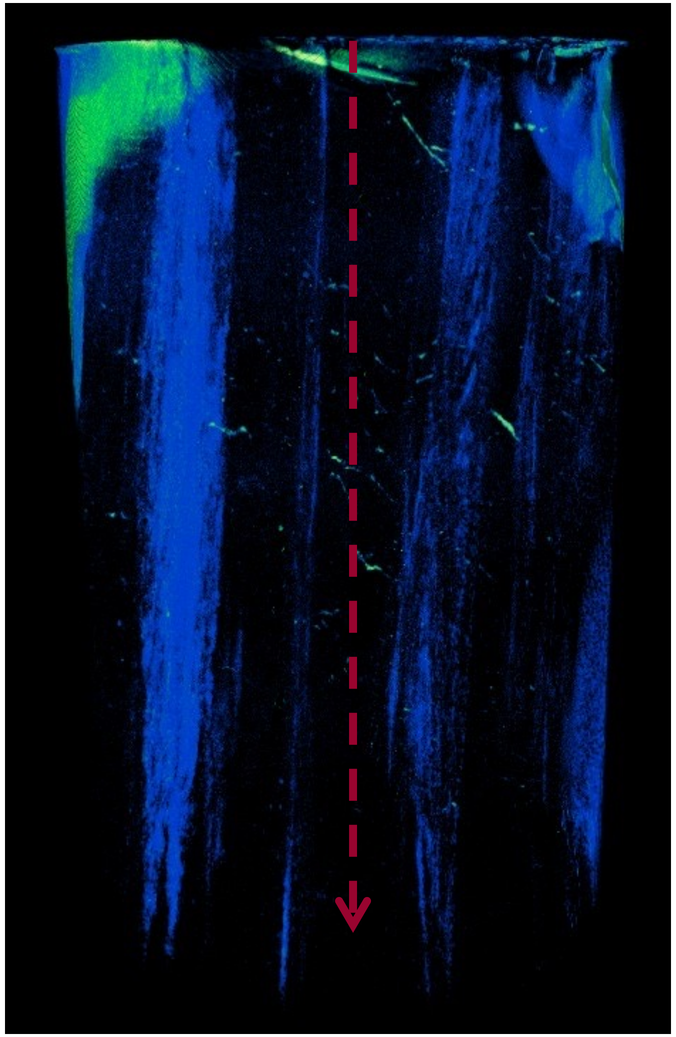
# Coreflood Simulations for asphaltene deposition

- Inject live fluids
  - Gradual pressure depletion to precipitation onset
  - Fluid-fluid interactions
- Permeability decrease & wettability alteration
  - Deposition at coreflood injection face
  - Deposition throughout core plug
- Is there deposition? Examine dissolvers and repeat study



# Visualising areas of asphaltene deposition



# Summary: organic scale studies

- Bottom Hole Sampling
- Crude Oil and Water Characterization
- PVT Fluid Properties, depletion, onset flocculation phase envelopes, Aasays of composition for potential recombination
- Other fluid analyses: GC/MS, ICP, IR, oil in water, solids, water chemistry
- Fluid/fluid incubation bottle tests
- Onset of flocculation precipitation
- Asphaltene Inhibition dosage bottle tests
- Asphaltene inhibition flocculation dosage tests
- Rock flowrate dependency due to pressure drop and or flowrate simulations investigating streaming potential and or fines migration solids movement
- Rock/Fluid/Fluid compatibility simulations various excluding and including full well operations sequence
- Asphaltene inhibitor treatment in the near-wellbore (evaluation for compatibility)
- Standalone fines migration without asphaltene inhibitor as a comparison.
- Nano CT investigation for deposition in all core flood simulations
- Pore lining Cryogenic SEM for all coreflood simulations

# Final thoughts

- Scaling (inorganic and organic) can have a significant impact upon inflow
- So it's not a scientific study: there is a real-world use for understanding what might be happening
- If we can understand the types of scale & conditions that they form under, we can move towards removing or avoiding them. Inhibitors and dissolvers exist!

- How to avoid issues?
- We need to understand our specific reservoir & conditions
- Simple: study, understand, look at options & solutions
- Just because something has worked elsewhere, or "should" work here, doesn't mean that it will. **Each reservoir is unique in physical and chemical properties**

# Any Questions?

Ask Justin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