Water shut-off with biopolymer - Alvheim

NPD Technology Day
Stavanger 7 June 2022

Kåre Langaas (Aker BP)

Material published in SPE-195485-PA

Outline

- Challenge and Vision
- A pilot done accidentally at Alvheim in 2013-2014 showed the potential
- Research w laboratory studies to understand and improve
- Alvheim field pilot plan 2022 and continued research
- Conclusions

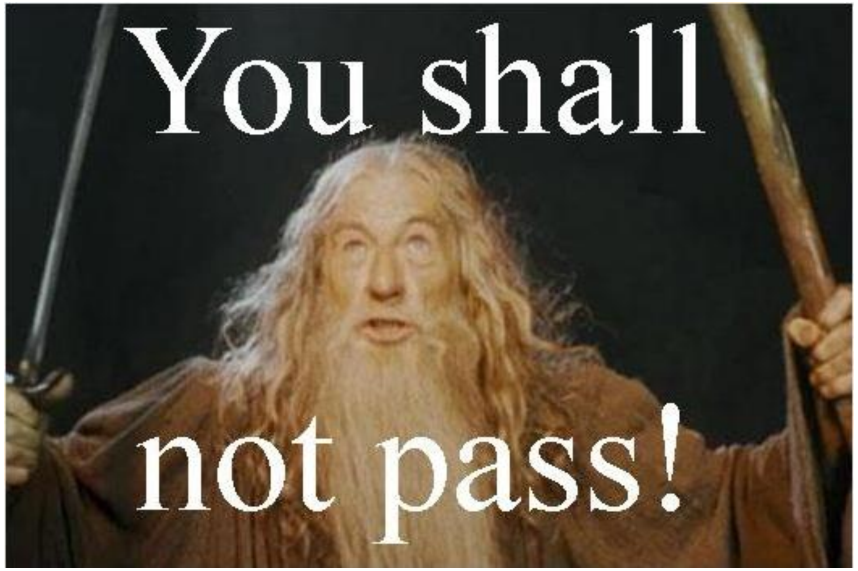
Challenge and Vision

Challenge

- A lot of older wells have zones producing 100% water
  - Water production uses energy
  - Water production might limit oil production
- Mechanical intervention like straddles can be expensive and risky
- Many wells like MLT wells on Alvheim and Ivar Aasen has no access to lower completion
  - Not possible to set a plug or straddle
  - Bull-heading is only option
- To successfully shut-in water, all methods depend on zonation in the reservoir and in the well (e.g. swell packers in shales between producing zones)

Vision

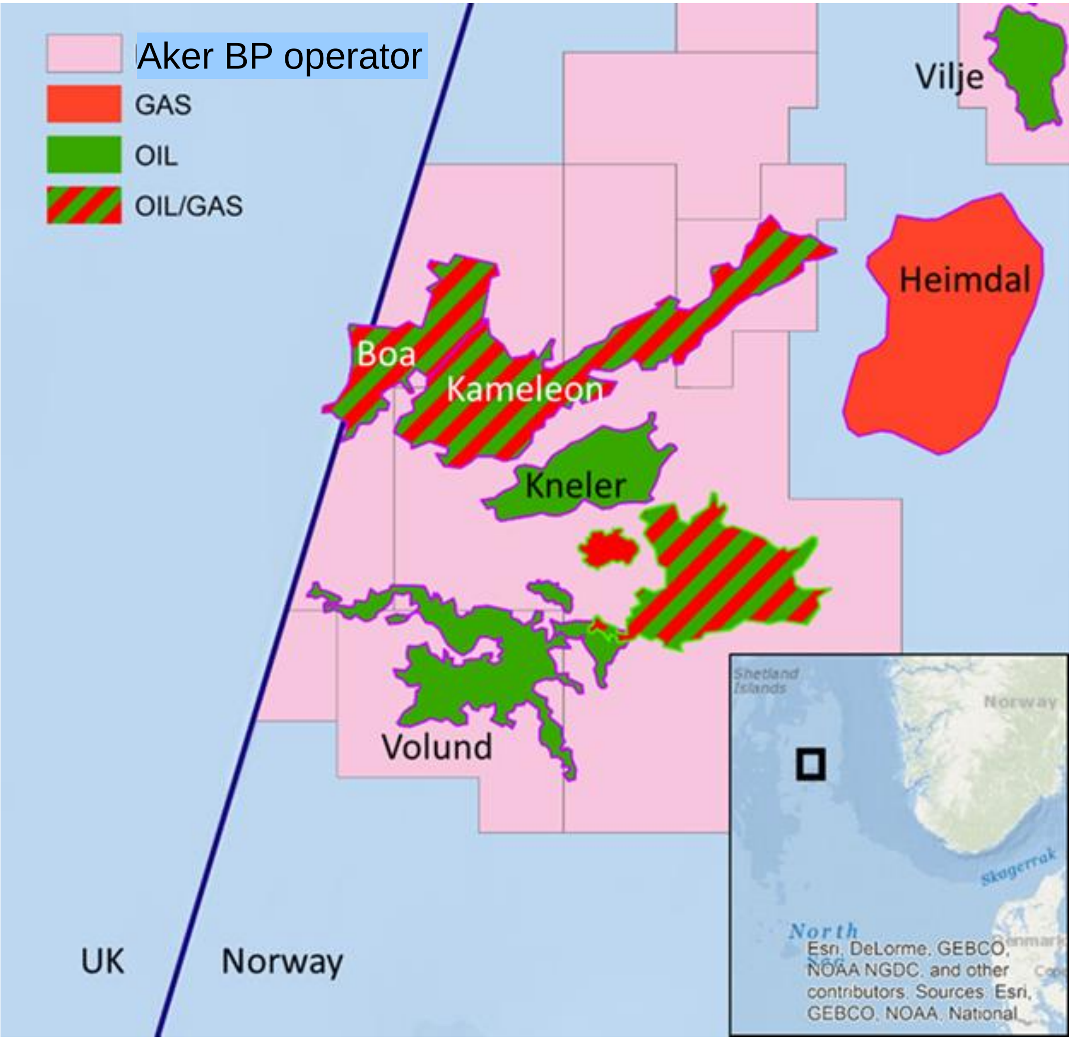
- If conditions are in place:
  - High degree of zonation in the reservoir and in the well
- Bull-head a fluid that shuts off water zones while not impairing the productivity of the oil producing zones



Introduction – Alvheim Field and Kneler accumulation

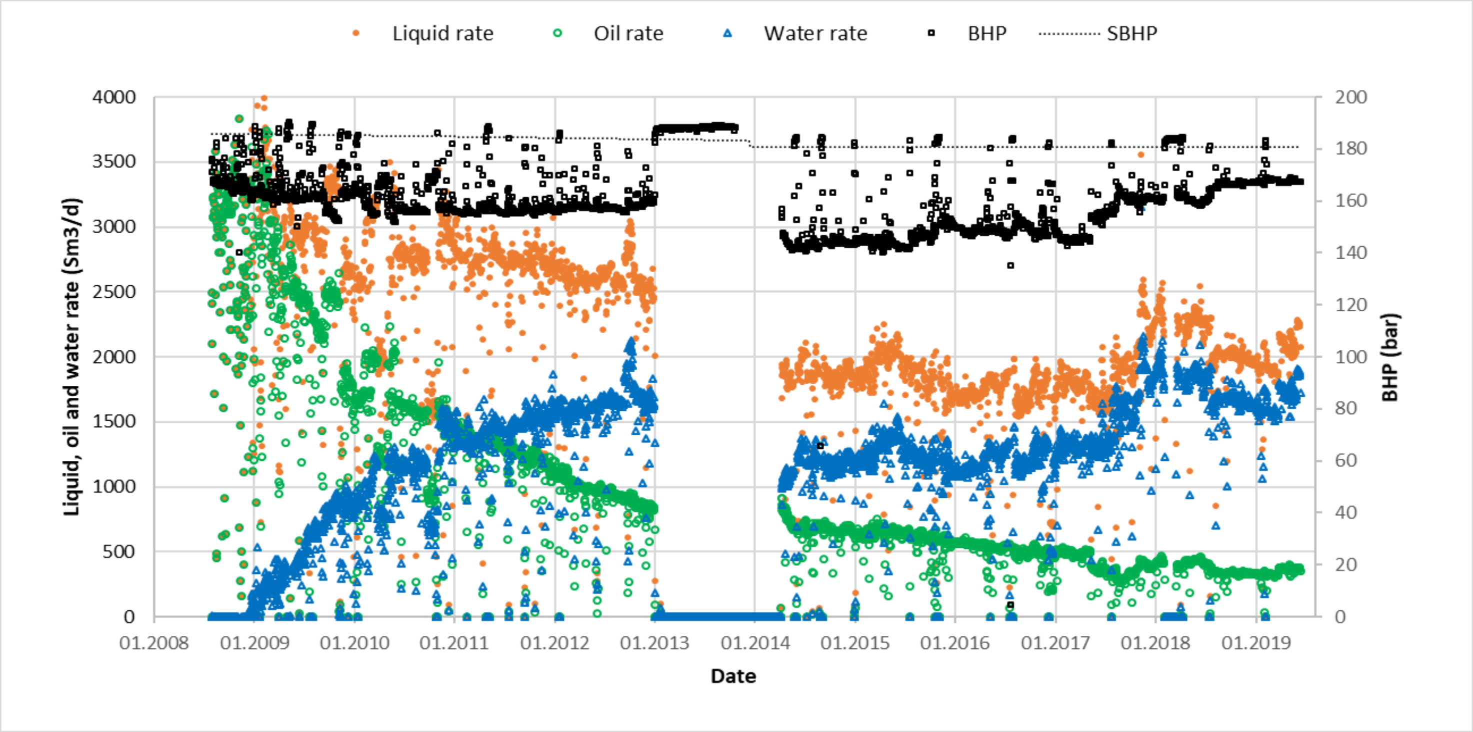
- Offshore Norway, Paleocene, Turbidite
- Within the Norwegian blocks Aker BP is the operator with a 65% ownership while ConocoPhillips and Lundin hold 20% and 15%, respectively.
- The field is composed of several low relief hydrocarbon accumulations within the Heimdal Formation, known as Boa, Kameleon and Kneler.
- The Kneler accumulation is up to 70 m thick and comprises of undersaturated oil detached from the rest of the Alvheim area.
- Production performance has shown that most wells have good pressure support by the aquifer, but also that stratigraphically compartmentalized segments exist.

Property	Value
Porosity	0.25 (fraction)
Permeability – horizontal (effective)	1 D
Permeability – vertical (effective)	10 mD
Initial (2008) OWC	2112 mTVDMSL
Initial (2008) reservoir pressure @ OWC	203 bars
Reservoir temperature	68 °C
Oil density at surface conditions	837 kg/Sm^3
Oil bubble point	135 bars



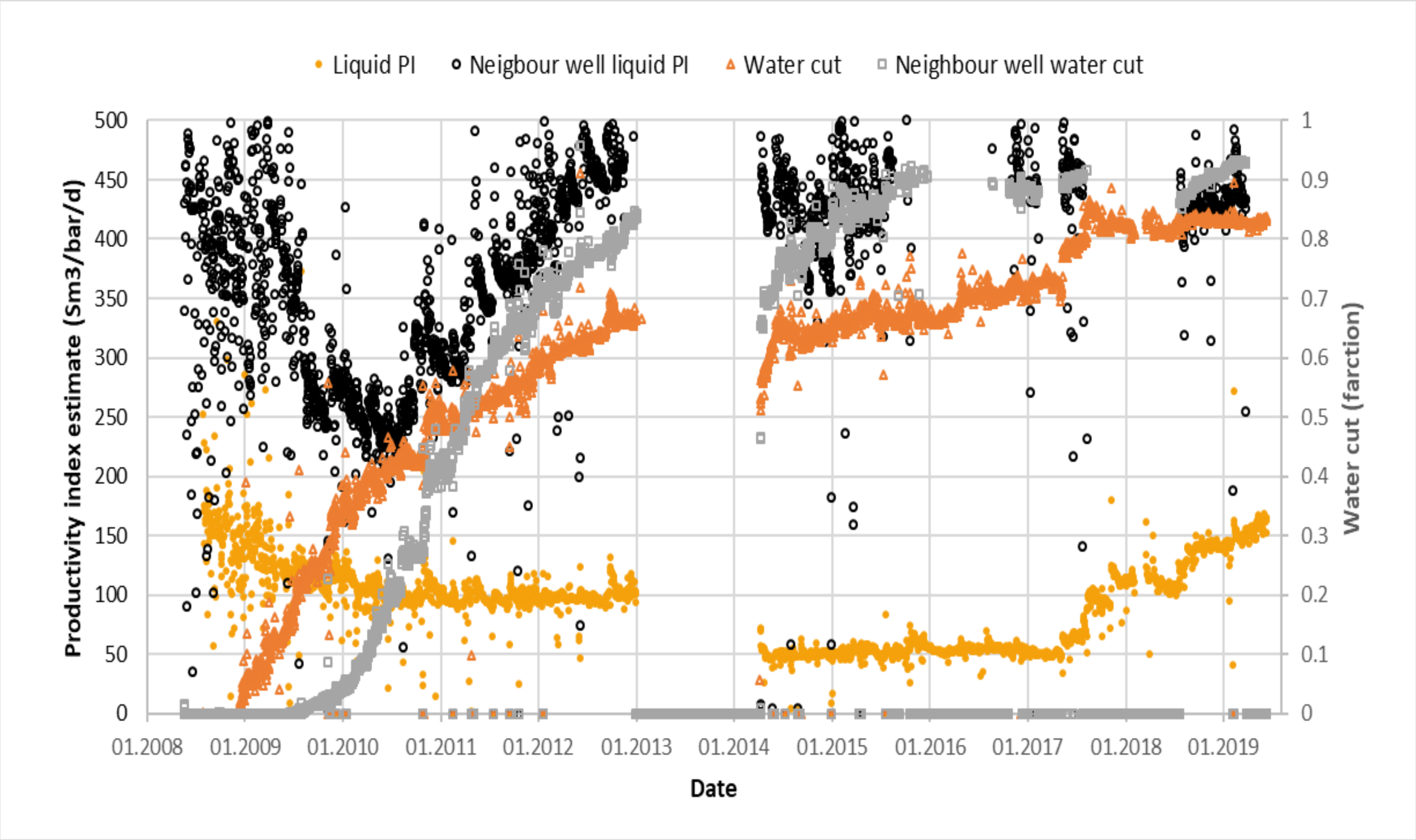
Introduction – polymer injection in two Kneler wells

- In 2013, an intervention campaign was performed to change out the production tubings in two Kneler wells.
- Brine and a polymer were bull headed to remove possible hydrocarbons before the old production tubings were pulled out.
- Normally a starch-based polymer with short life-time is used for this kind of operation to not impair the well productivity.
- Due to availability issues, another polymer, drilling-grade xanthan, was used in the second well.
- The well productivity was reduced in the xanthan-treated well.



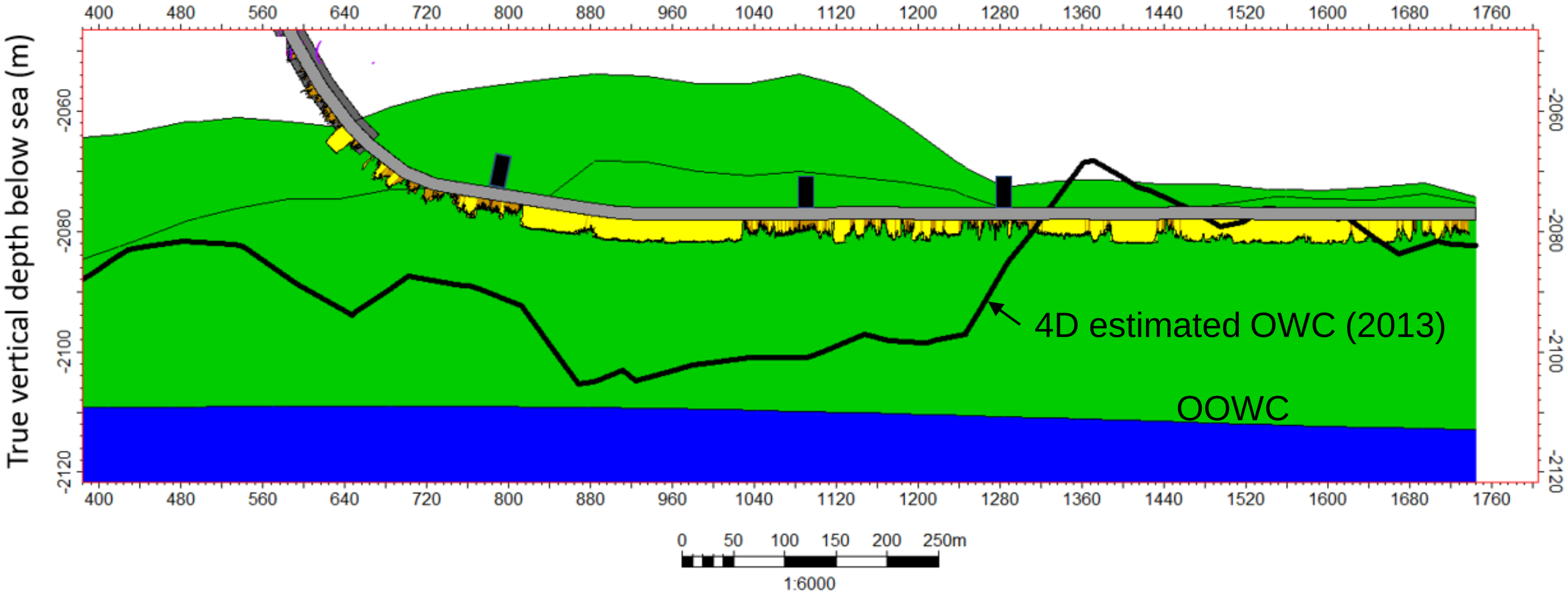
Introduction – polymer injection in two Kneler wells

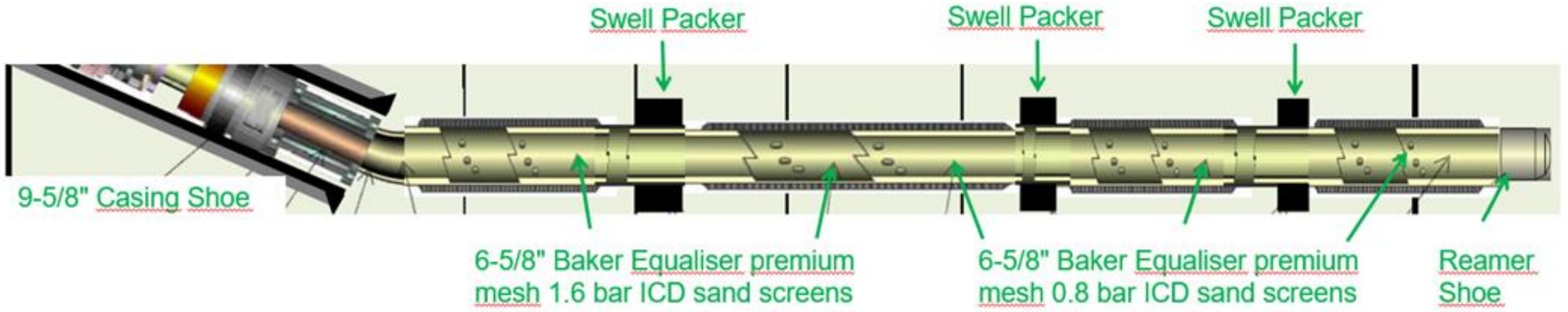
- The first well in the workover campaign, where starch-based polymer was used, showed no reduction in liquid PI
- This “neighbor” well has the same screens, similar ICD settings, and geology as the xanthan treated well. The shut-in time and water-cut before the workover were also similar
- Hence, the reduced liquid PI in the xanthan treated well is most likely explained by the xanthan polymer
- Reduced PI period was 3.5 years



Xanthan treated well - details

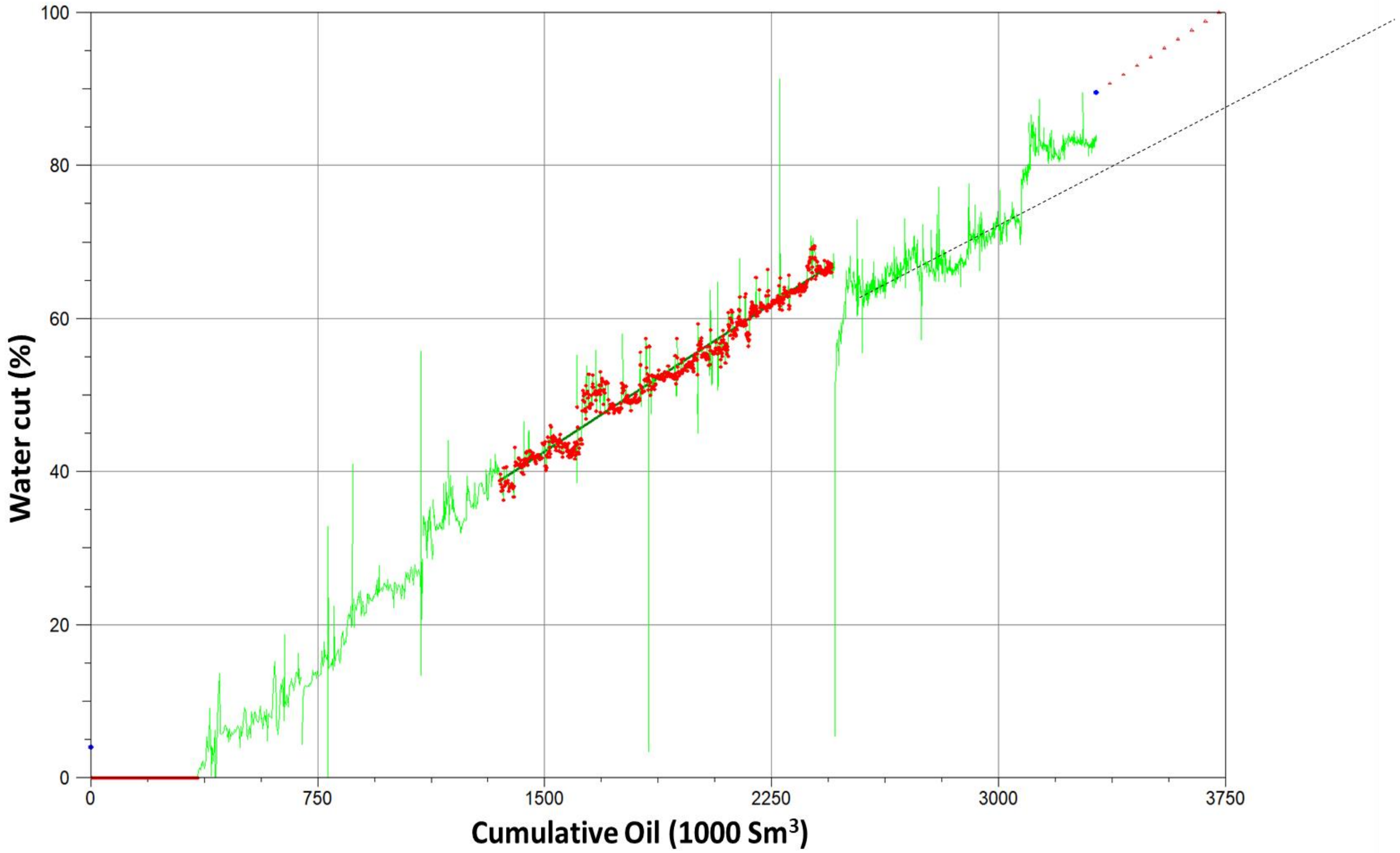
- The PI of this well was low as compared to most Alvheim wells, likely explained by some kind of compartmentalisation
- 4D seismic indicate uneven OWC movement
- The polymer plugging capability is likely proportional to effective flow channel diameter
  - PI reduction most likely explained by formation impairment (not to plugging of ICDs nor screen)





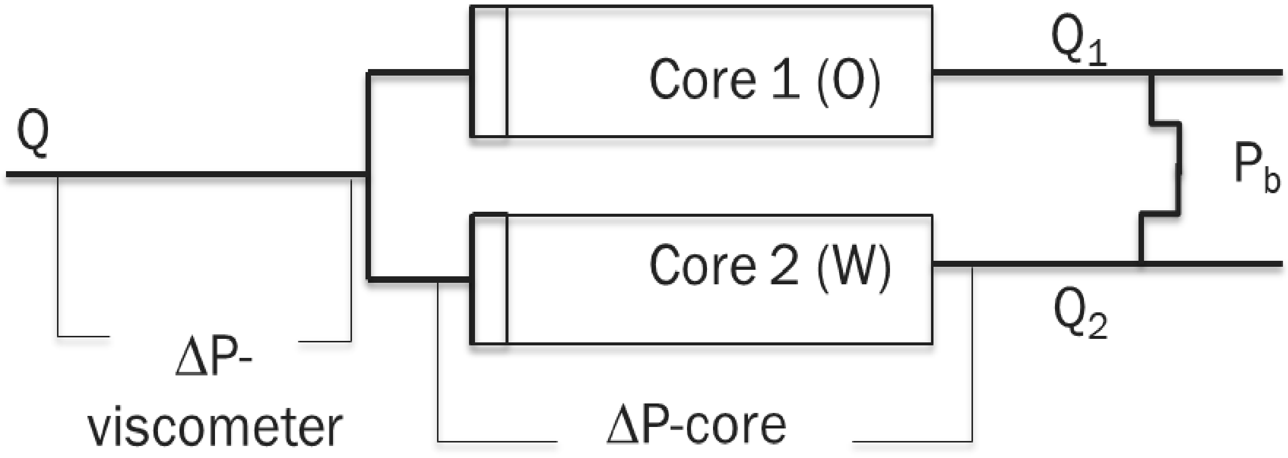
Xanthan treated well – step change in water cut trend

- The water-cut trend showed a step change
- Possible future EOR method for Alvheim and similar oil fields?
- R&D was initiated to understand more



R&D core experiment set-up

- Two cores mounted in parallell to represent a possible 2-layered reservoir
  - Core 1 – Oil at Swi
  - Core 2 – Water at Sorw
- A spacer ring (1 cm) at inlet end was used to allow for realistic external filter cake build-up and the possible back production of this filter cake
- The polymer was first injected into the combined core system
- After a shut-in period of typically 3 days, the cores were back-flooded individually, with oil in the oil core and with brine in the water core



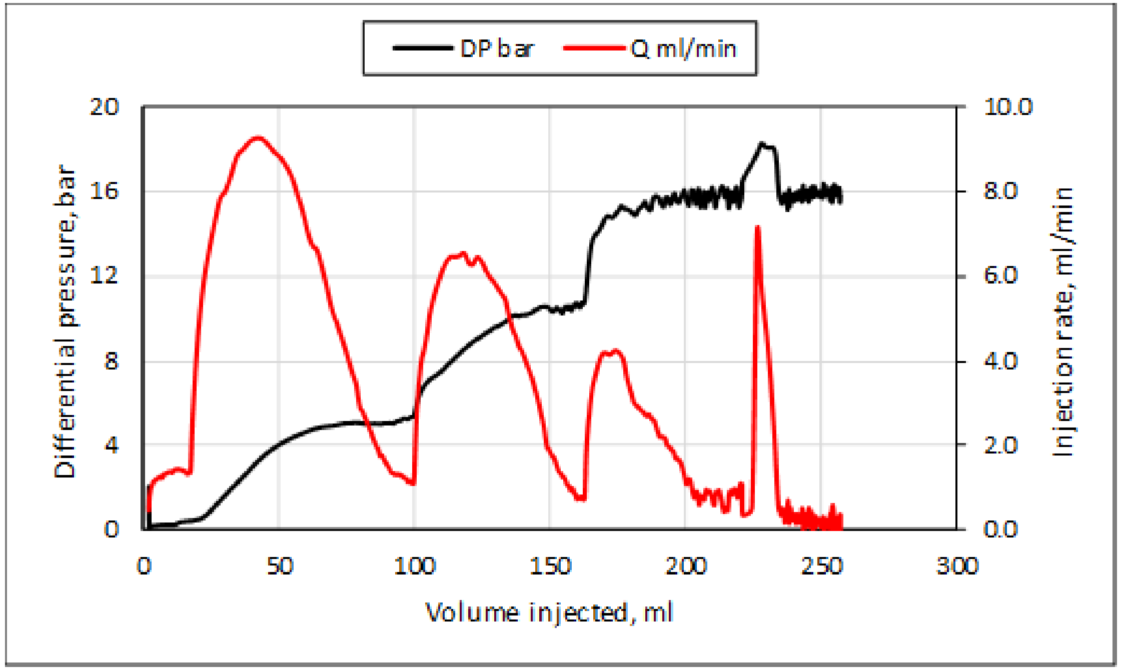
Drilling-grade xanthan into two Bentheimer cores

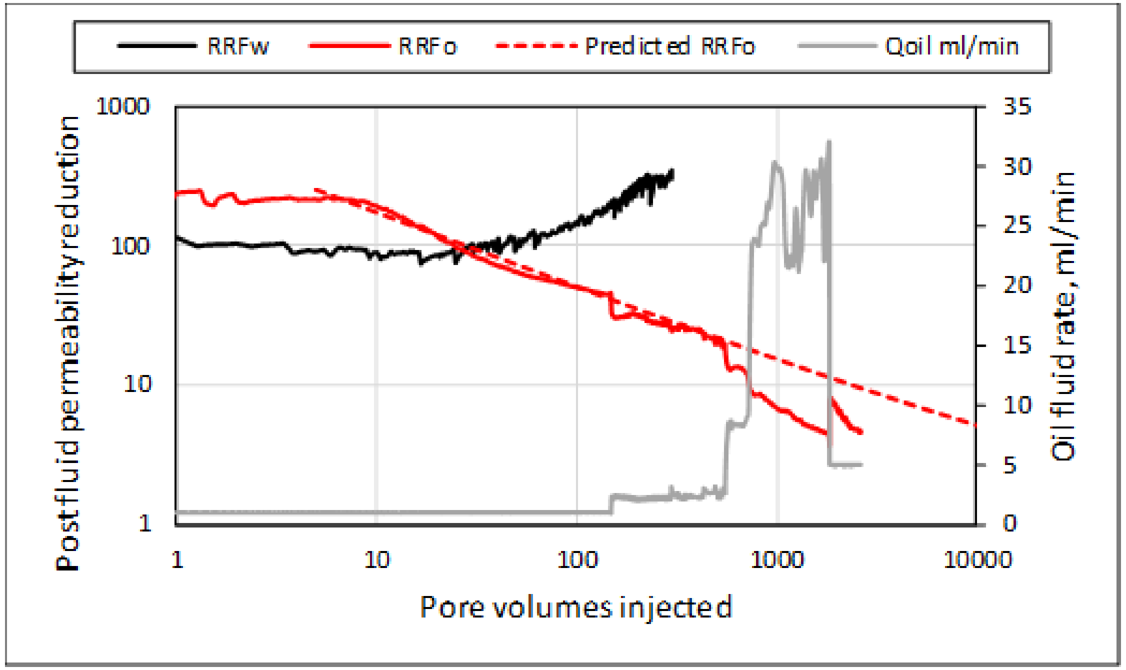
During polymer injection

- Both oil core and water core flushed with polymer
- Large permeability reduction in both cores

During back production

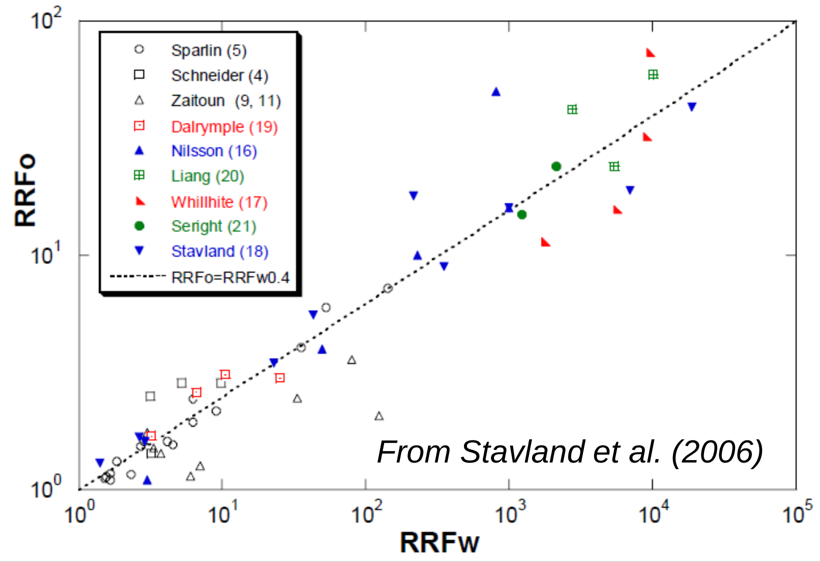
- Brine back-flow does not help to improve permeability
- Oil back-flow help to improve permeability
- End state RRFw = 370; RRFo=4.6
- DPR = 80 and further improving with time

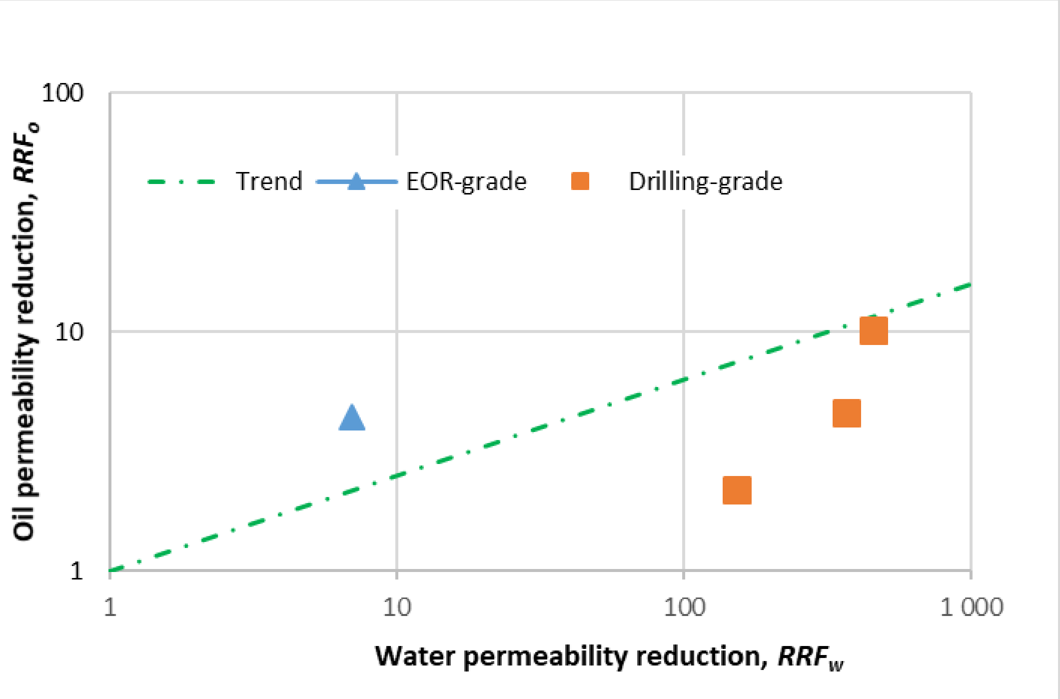




Summary of initial R&D

- Core results with drilling-grade xanthan are better than literature trendline as reported by Stavland et al. (2006)
- RRFo was still improving when experiments were ended
- Cutting the cores in two showed higher permeability reduction at polymer inlet side and that polymer debris at surface (filter cake) can play a role for water shut-off





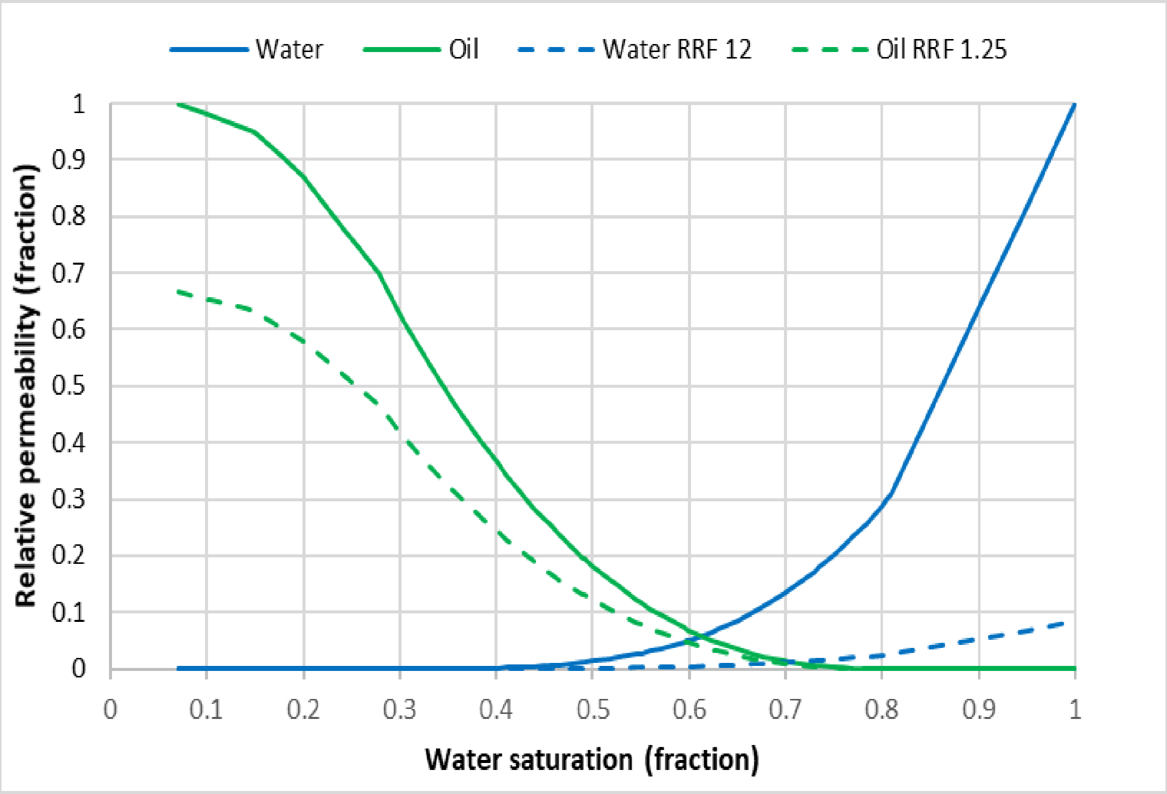
Upscaling the core results to the dynamic model

Practical implementation

- Well model RRF used to scale the relative permeability to water and oil in the inflow model

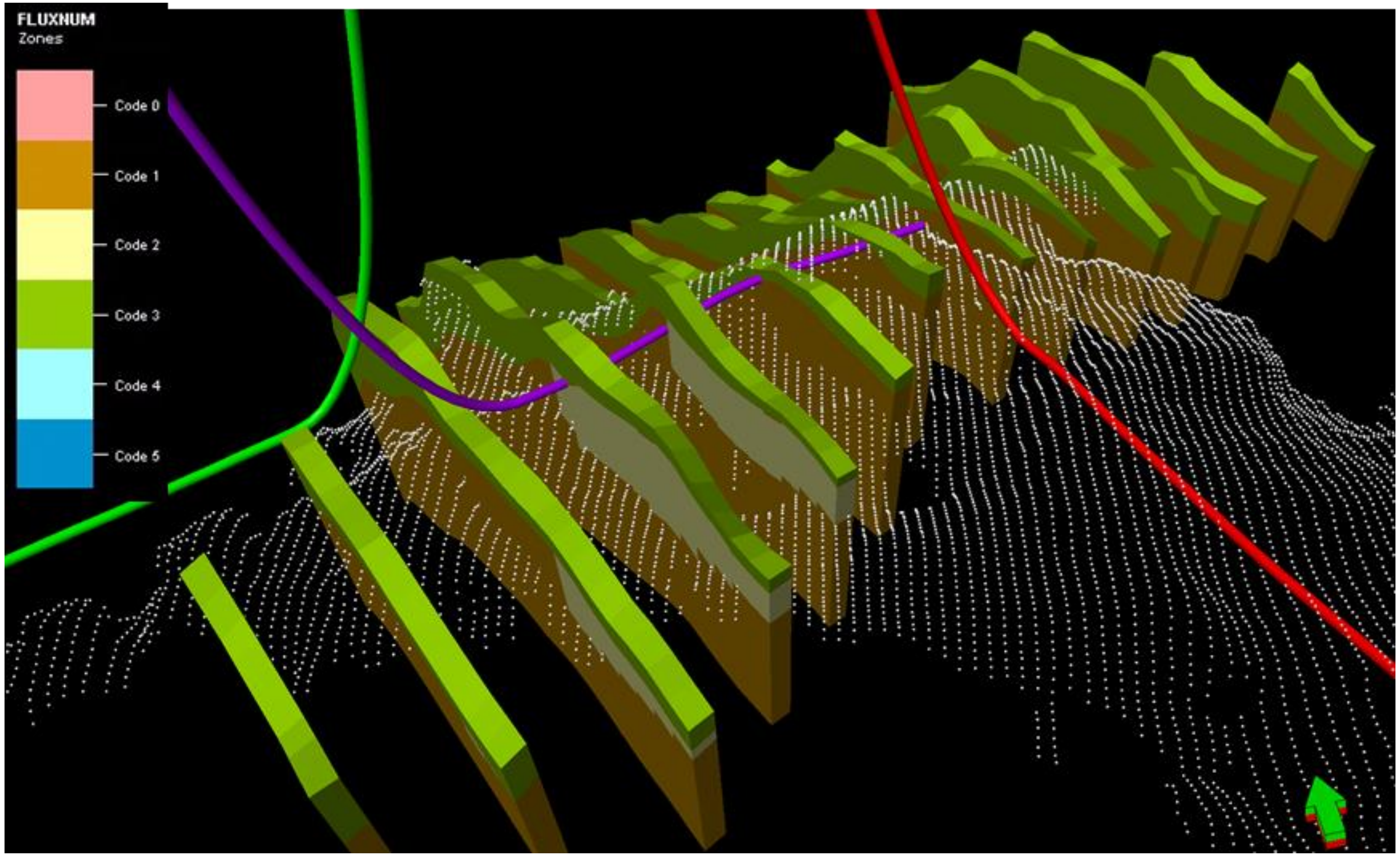
- Scaling used in history matching
  - RRFw well = 12; (RRFw core ~75 +)
  - RRFo well = 1.25; (RRFo core ~2.6 +)

- Practical implementation
  - Import this scaled relative permeability to petrel/Eclipse
  - Change COMPDAT item # 7 at the correct times



History matching the water shut-off in the reservoir model

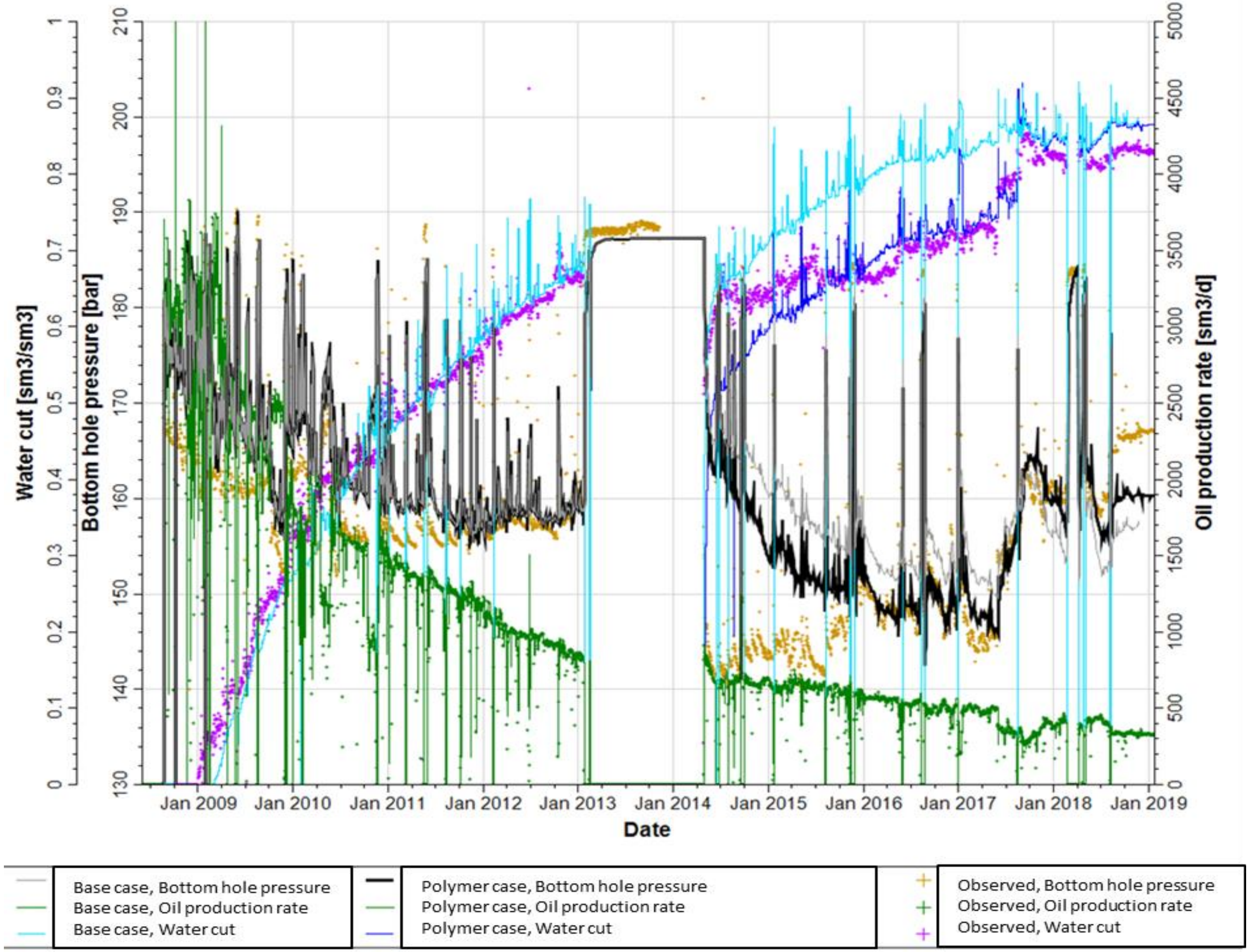
- Sector model from latest full field geomodel, not yet adjusted to 4D seismic data
- Upper zone (KR3) green
- Lower zone (KR2) brown
- White dots is 4D estimated OWC mid 2013
- Made an extra zone (yellow) to try improve match vs 4D seismic data



History matching

Well data match

- Auto-match on oil rate
- By introducing the extra segment, the match to 4D seismic, water cut and pressure were improved
- Base case (no polymer)
  - Too high water cut
  - Too high PI
- Polymer case
  - Acceptable match to average water cut and PI throughout the whole history of the well
- Overall, this history match aligns well with the laboratory core studies



Continued R&D and new pilot plan

R&D

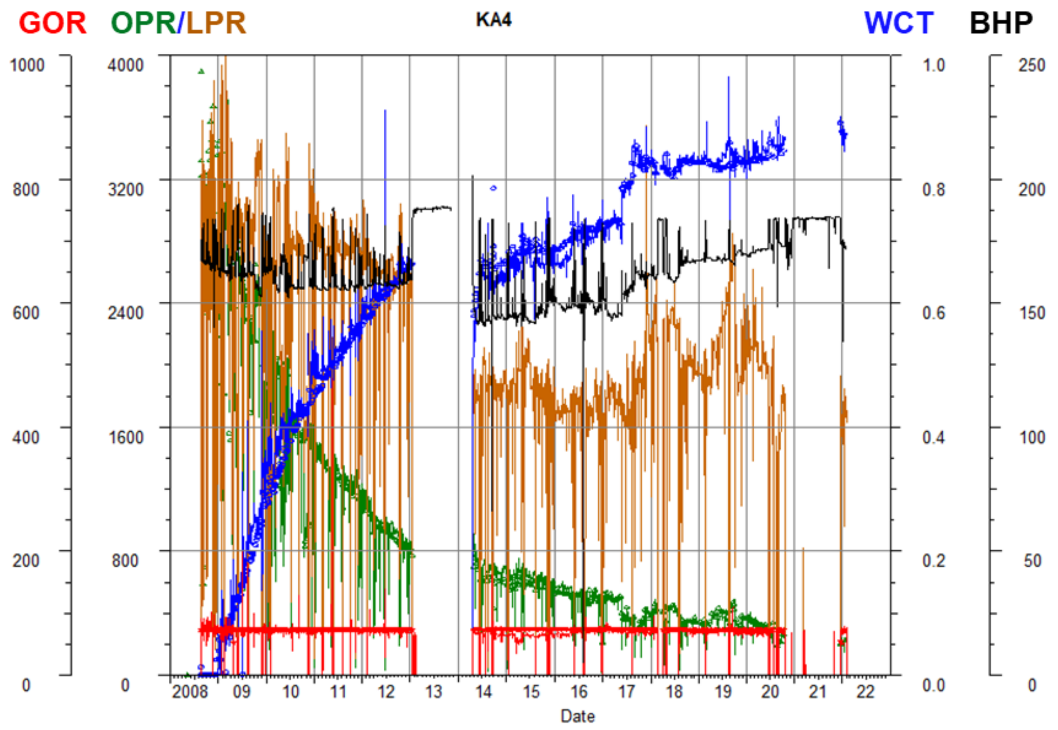
- Phase 1 (NORCE 2016-2017)
  - Focused on xanthan polymer
  - Published with all details in SPE-195485-PA
- Phase 2 (NORCE 2018-2020)
  - Addressed alternative biopolymers and longer cores
  - Candidates with longer life time
  - MSc study
- Phase 3 (NORCE 2022)
  - Alternative fluid system – same vision

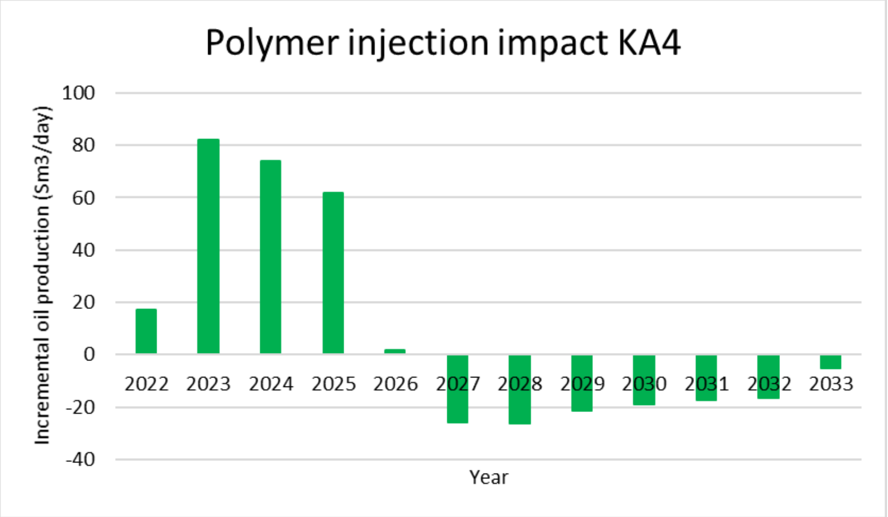
Pilot plan

- Pilot plan delayed due to Covid
- Current plan is to repeat xanthan bull heading in the same Alvheim well
  - Business case made using history matched model in forecast mode w new similar treatment
- Operations planned ~ Q4 2022
  - Establish stable production performance before polymer treatment
  - Treatment similar as in 2013
  - Evaluate impact over next years

New field pilot - impact

- Start-up: December 1st 2022
- Incremental resources: 0.2 mmbbls
- In addition accelerated oil production
- Robust economy + valuable learning
- History matched reservoir model used to estimate benefit

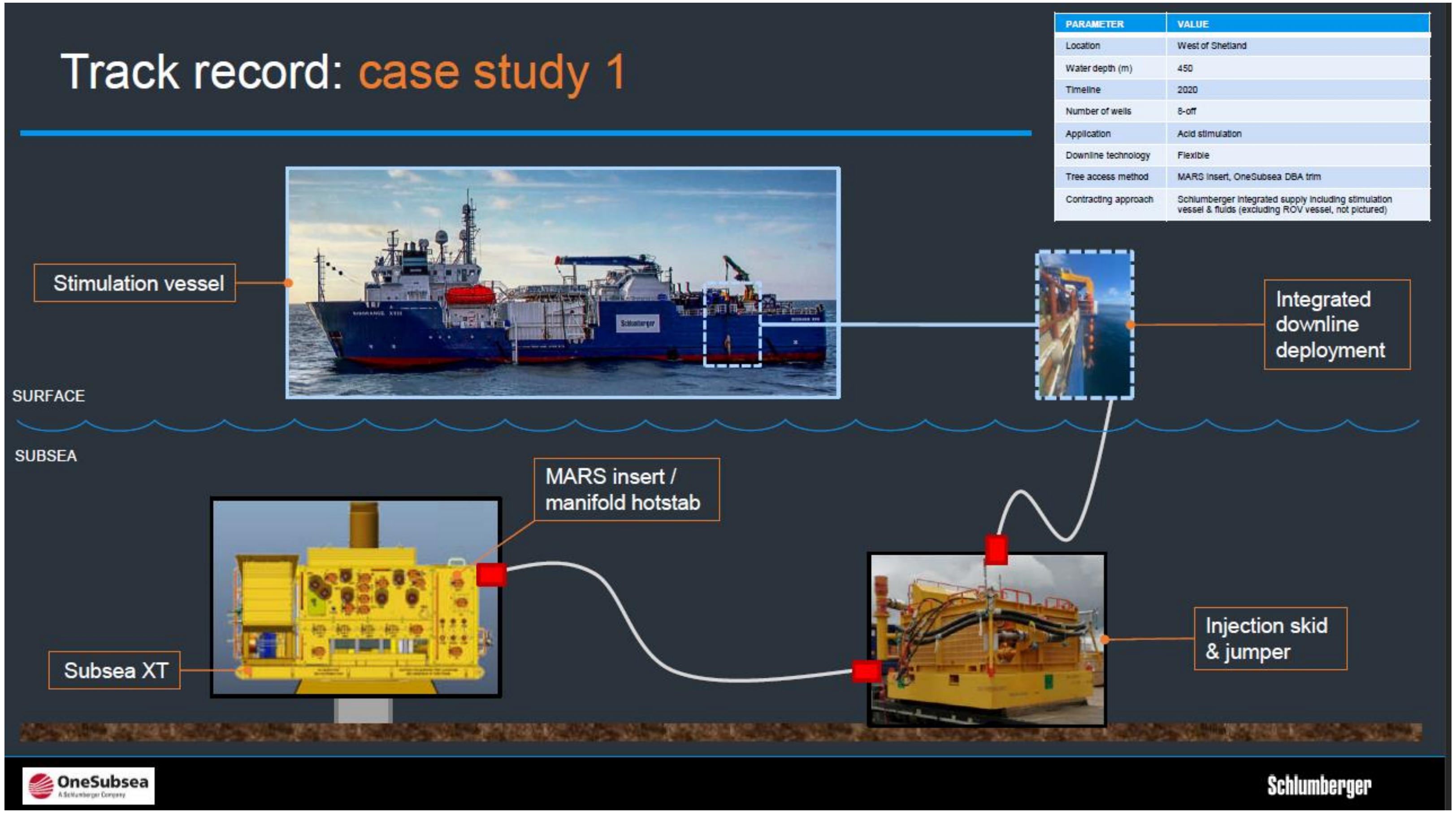




New field pilot – operational plan

Typical set-up – information received from OneSubsea

- IMR vessel can store the polymer / brine in the vessel tanks
- Alvheim XMT need a choke insert adapter – part of the OneSubsea delivery
- Downline part of Onesubsea deliverable
- Pumping spread to be hired through IMR contractor / Aker BP direct
- Choke / Choke insert to be retrieved / installed using Aker BP's IRT (Integrated running tool)



PARAMETER	VALUE
Location	West of Shetland
Water depth (m)	450
Timeline	2020
Number of wells	8-off
Application	Acid stimulation
Downline technology	Flexible
Tree access method	MARS insert, OneSubsea DBA trim
Contracting approach	Schlumberger integrated supply including stimulation vessel & fluids (excluding ROV vessel, not pictured)

Conclusions

- The method by bullheading drilling-grade xanthan polymer shows potential as a water shut-off method
- The water shut-off lasted more than 3 years at reservoir temperature of 70°C and under high drawdown
- Lab studies revealed a favorable DPR ratio ~ 45-80 and improving further with time
  - The core result is better than the trend from earlier published results
- A reservoir model gave a satisfactory history match on the polymer effect using permeability reduction well aligned with the laboratory core flood experiments
  - Reservoir modelling method established to screen this EOR method for candidate wells
- New Xanthan-based polymer pilot planned at Alvheim (~Q4 2022)
- R&D has been key for understanding and is ongoing chasing further improvements

Acknowledgements

The author would like to thank

Aker BP, ConocoPhillips and Lundin for the permission to present this work

Arne Stavland, Daniel Strand and Siv Marie Åsen for R&D work at NORCE

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