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Optimizing Enhanced Oil Recovery: The Benefits of Preceding ASP and SP Floods with Polymer Flooding

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SNF

Let's connect!

Outline

- Current State of Oil Industry
  - Discussion of Energy Transition – annual reports to shareholders, etc.
  - Possibility of "Stranded Assets" – early production critical.
  - Environmental Pressures – Carbon Footprint of Production Operations
- Enhanced Oil Recovery Increasingly Advantageous
  - Accelerate production of oil. Reduce potential for stranded asset.
  - *Lower carbon footprint* – lower water cut of production wells.
- Polymer Flooding vs. (A)SP (surfactant based, low Interfacial tension).
  - Faster implementation vs. maximum recovery.
  - Base Case has been for surfactant flood (A)SP is to follow a water flood. *1000's of lab core floods done this way*.
  - Proposing an optimized scenario that accomplishes both goals.
  - Evaluation of potential drawback of injecting polymer first. Experimental data and simulation results.

Field Development – Critical Issues Today

- New and Existing Assets. How should they be produced?
  - Oil field production can last 70+ years. How much hydrocarbon will be needed during those 70 years?
  - Is there a real possibility for "Stranded Assets"? Is there a risk that valuable assets will be left in the ground if we do not produce it soon enough?
  - What are the options to accelerate production, and lower carbon footprint?
  - How reliable are these options?
- Polymer Flooding – reliable, field tested, enhanced viscosity of aqueous phase. *Not chemically complex*. Leaves capillary trapped oil behind (Sor 25-35%, water wet sandstone).
- Surfactant Flooding (A)SP – highest recovery, more complex. Logistics, supply, formulation, effect of changes in salinity on phase behavior, etc. Can desaturate rock to less than 5% oil saturation.
- New developments in ASP improve economics (references, Oman field trial). Economics support maximum recovery (< 5 % remaining oil). Wait for surfactant formulation or start early injection of polymer.

Positive Aspects of Early Polymer

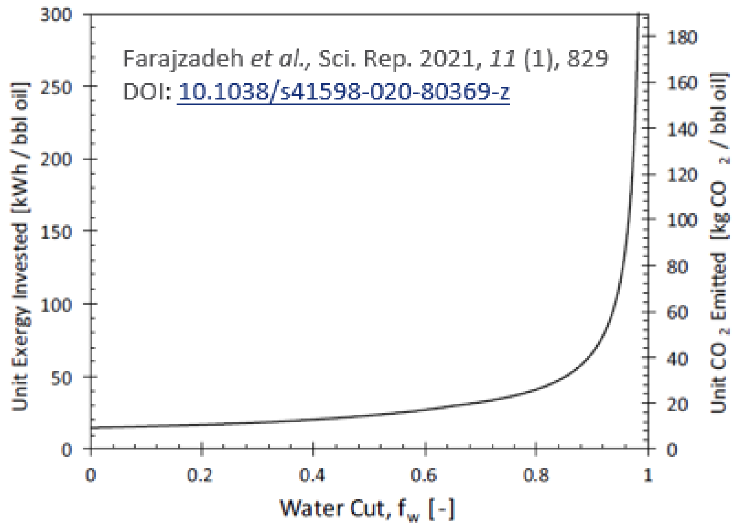
- *High chance of success.* Risk principally related to operational issues.
- Gain experience with injectivity, operational issues before utilizing expensive surfactant.
- Gain experience of reservoir response. Can tailor surfactant injection to responsive regions of the reservoir.
- Time to sort out logistics, supply of chemicals, field operations.
- Improved flow of surfactant into lower permeability zones?
- 9 month implementation time frame.
- Higher net present value earnings.

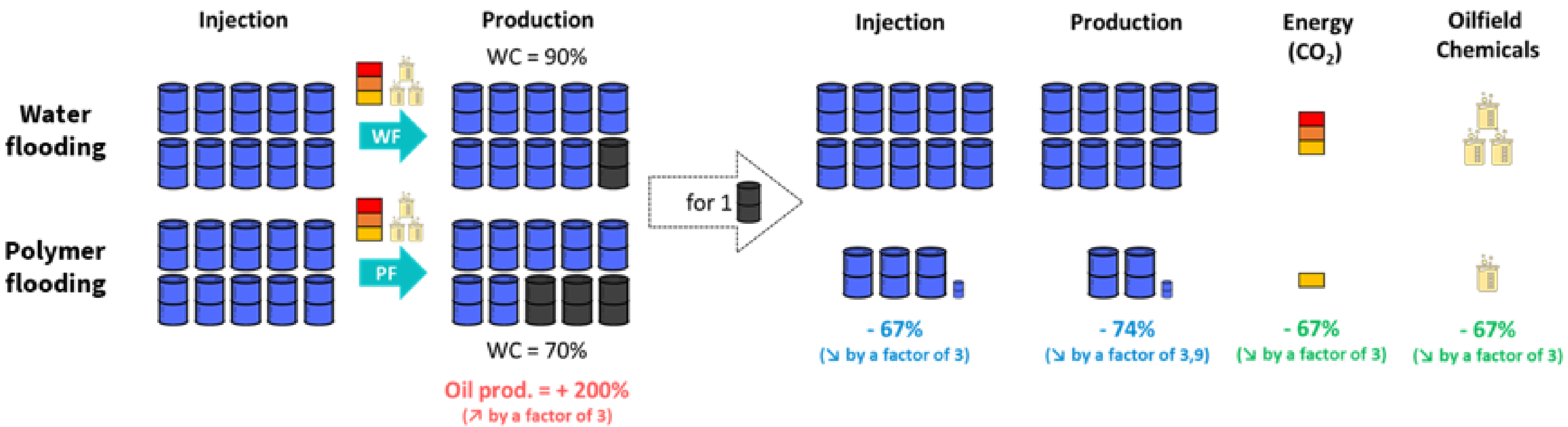
Negative Aspects of Early Polymer

- Less field experience with this scenario.
- *Viscous fluid injection ahead of surfactant bank. Slower propagation of surfactant. Injection pressure limited. 1D corefloods – lower throughput at constant pressure.*
- Reduced oil recovery?
- Why hasn't early injection of polymer been "the norm" to date?
- Reservoir connectivity is unproven, and water is the cheapest injectant.

POLYMER FLOODING & CO_2 SAVINGS

- 60% of the reservoir under water injection
  - Excessive water use = excessive CO_2 emissions
  - By adding polymer sweep is improved
    - Water cut ↘
    - Oil production ↗



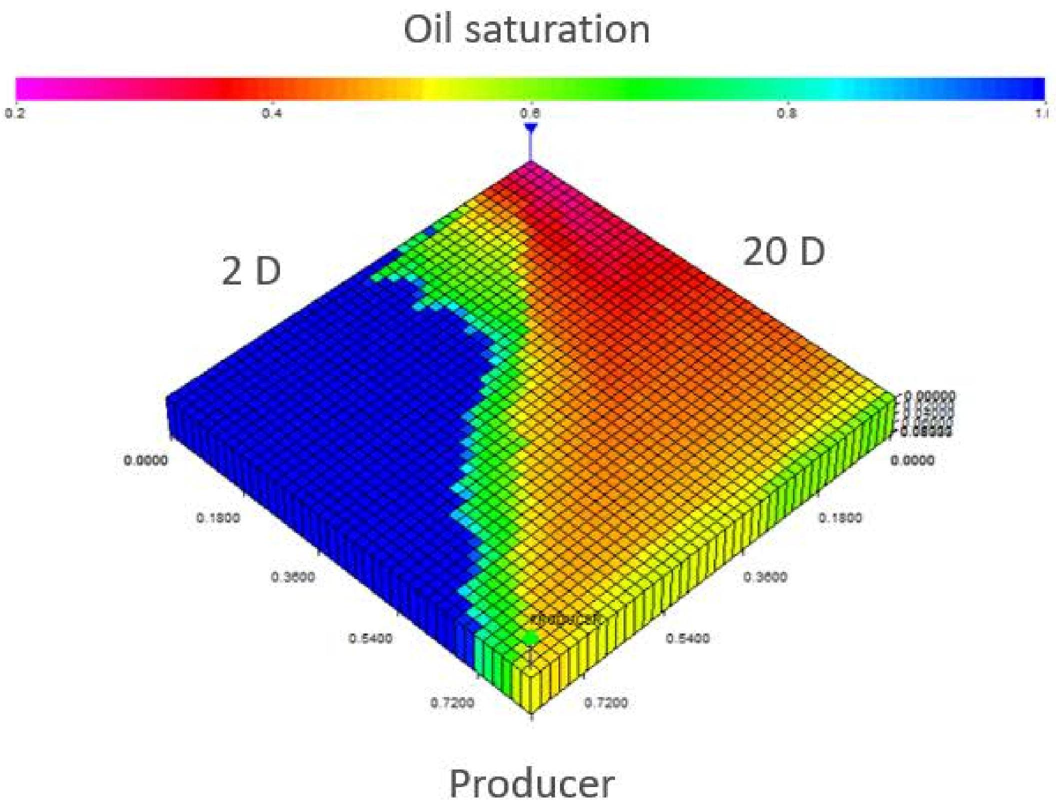


SPE 190271 - WF-ASP vs PF-ASP, 2D Sandpack Experiments

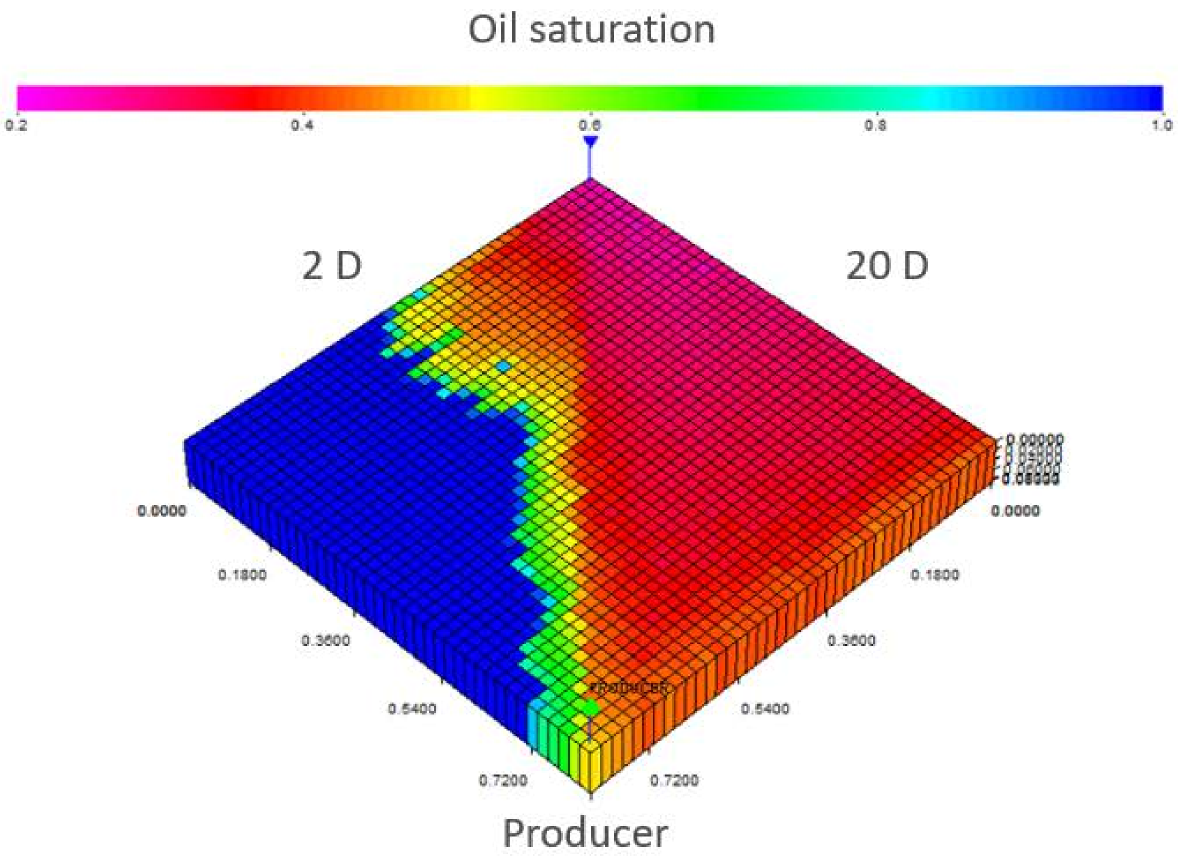
- Experimental Study, Aitkulov et. al.
  - Results –"*These series of experiments demonstrate the interaction of sweep efficiency and displacement efficiency of ASP flooding through visual observations. It demonstrates that the polymer flood – ASP flood combination is more effective than the waterflood – ASP flood combination.*"

- General Conclusion or Specific to this 2D Sandpack Experiment?
  1) Construct reservoir model with 10x permeability distribution similar to sandpack. Perform simulation with mechanistic model (UTCHEM). Oil recovery higher at all points in time with early polymer injection. No parameters modified or tweaked.
  2) Successful history match of laboratory sandpack experiment. Benefit of early polymer.
  3) Obtained simulation parameters by history matching Milne Point corefloods to use in field model.
  4) Applied these parameters in a heterogeneous field scale model. Tested scenarios, WF-ASP vs. PF-ASP.

Simulation of Heterogeneous Sandpack



ASP Flood After Waterflood



ASP Flood After Polymer Flood

Dual distribution model, parameters not modified. Early PF always has higher production.

Simulated Cumulative Oil Production

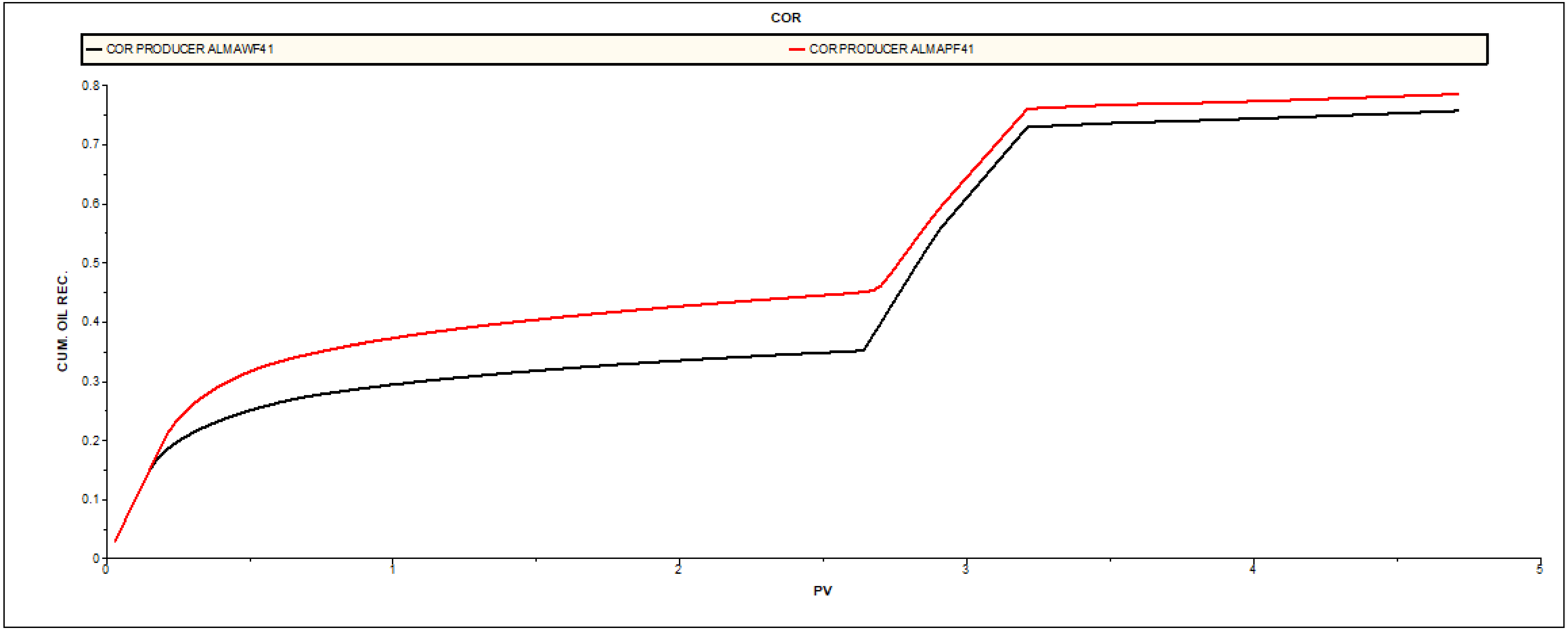


Fig. 3—Qualitative Example, Oil recovery is always higher with polymer flood prior to ASP flood (Q2; red) versus waterflood prior to ASP flood (Q1; black).

History Match of Experiment in Aitkulov et al.

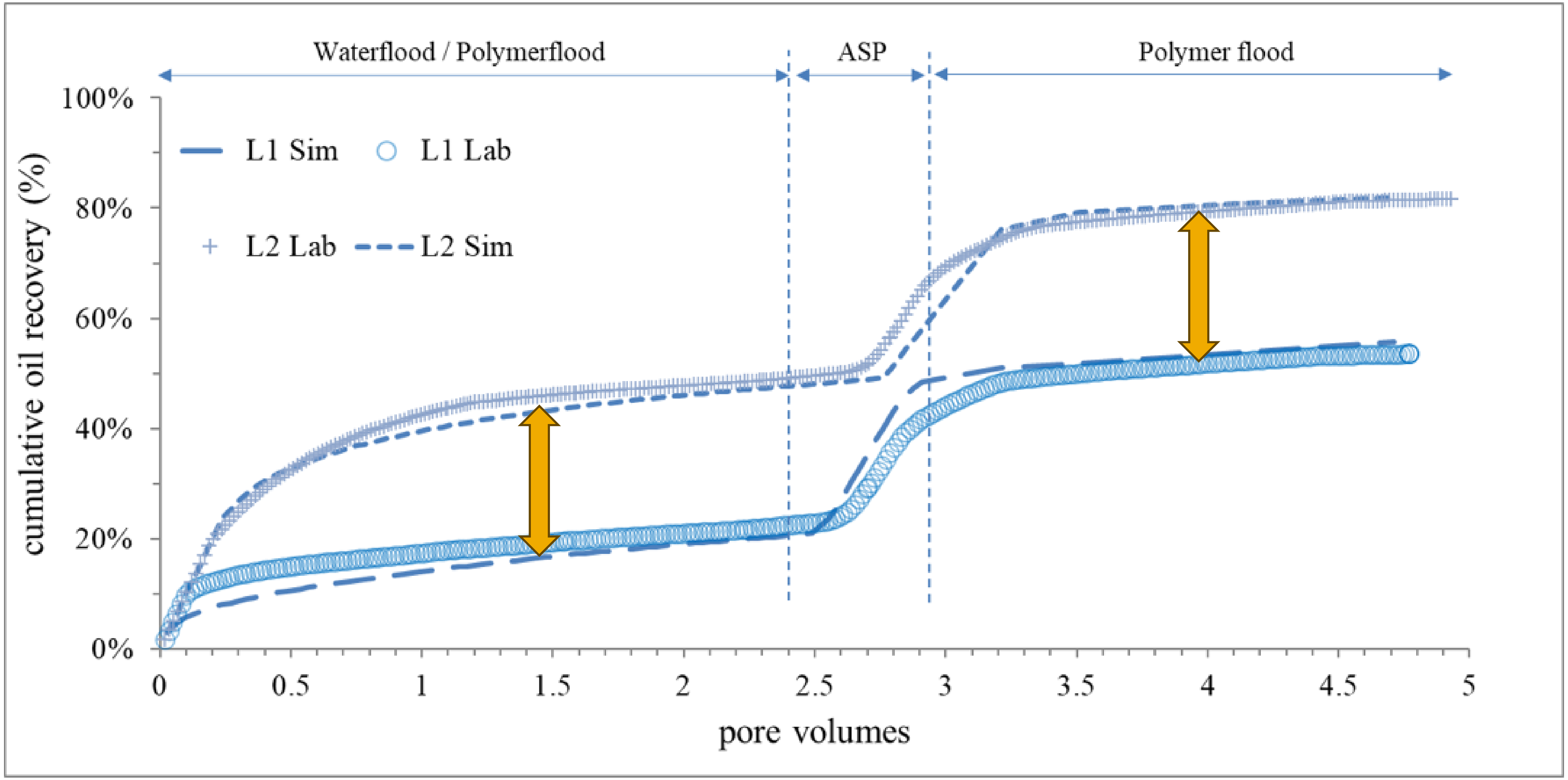


Fig. 4—History match of ASP laboratory experiments with waterflood prior to ASP flood (circles, dashed line) and polymer flood prior to ASP flood (crosses, dash-dot line).

Core Flood History Match – Parameter Determination

Milne Point Reservoir Core Floods with ASP

Table 2—SCAL, fluid, and reservoir properties used in Milne Point coreflood model.

Parameter	Value [Range]	Unit
$k_{rw}°$	0.25	-
$k_{ro}°$	1.00	-
n_w	5	-
n_o	2	-
S_{wirr}	0.20	-
S_{orw} (low N_C)	0.32	-
S_{orc} (high N_C)	0.00	-
μ_w	1	cP
μ_o	296	cP
φ	0.307	-
$\bar{k}$	3,234	mD
T_{res}	21	°C

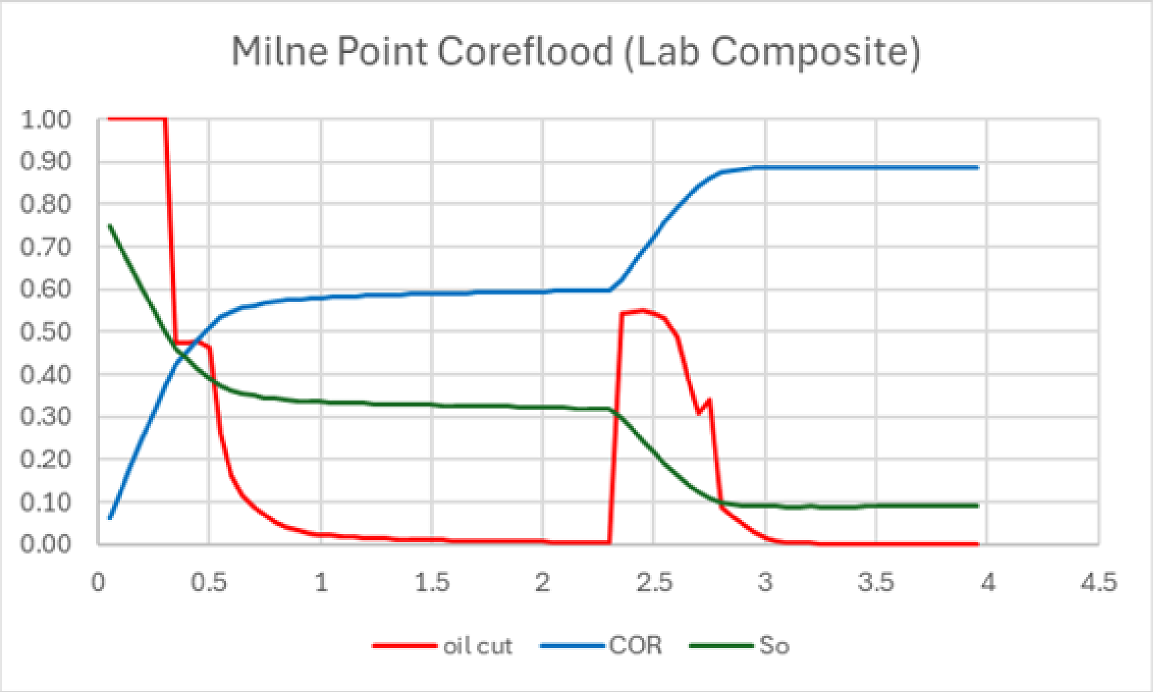


Fig. 5— Simulation in line with results from composite history match.

Desire to model realistic Milne Point field conditions. Parameter determination from laboratory corefloods.

Sector Field Model – Milne Point

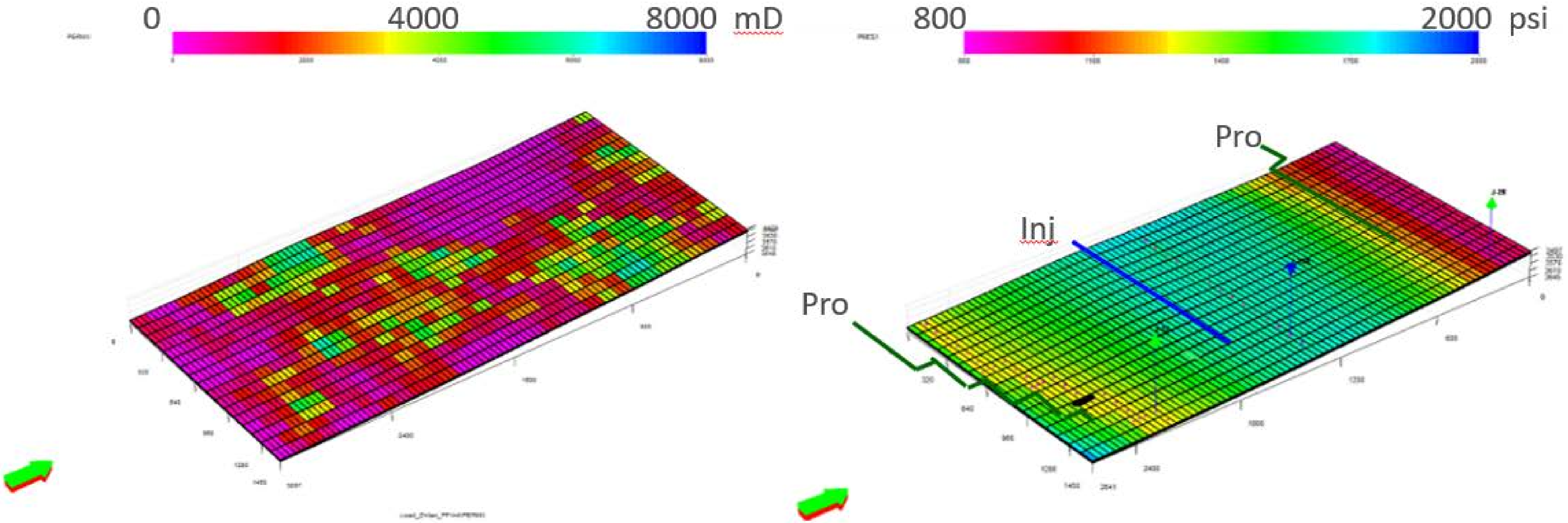


Fig. 6— Field model permeability (x & y), left, and initial reservoir pressure map with wells marked, right.

Fluvial Nb sand reservoir, channel apparent left to right.

Oil Production Prediction

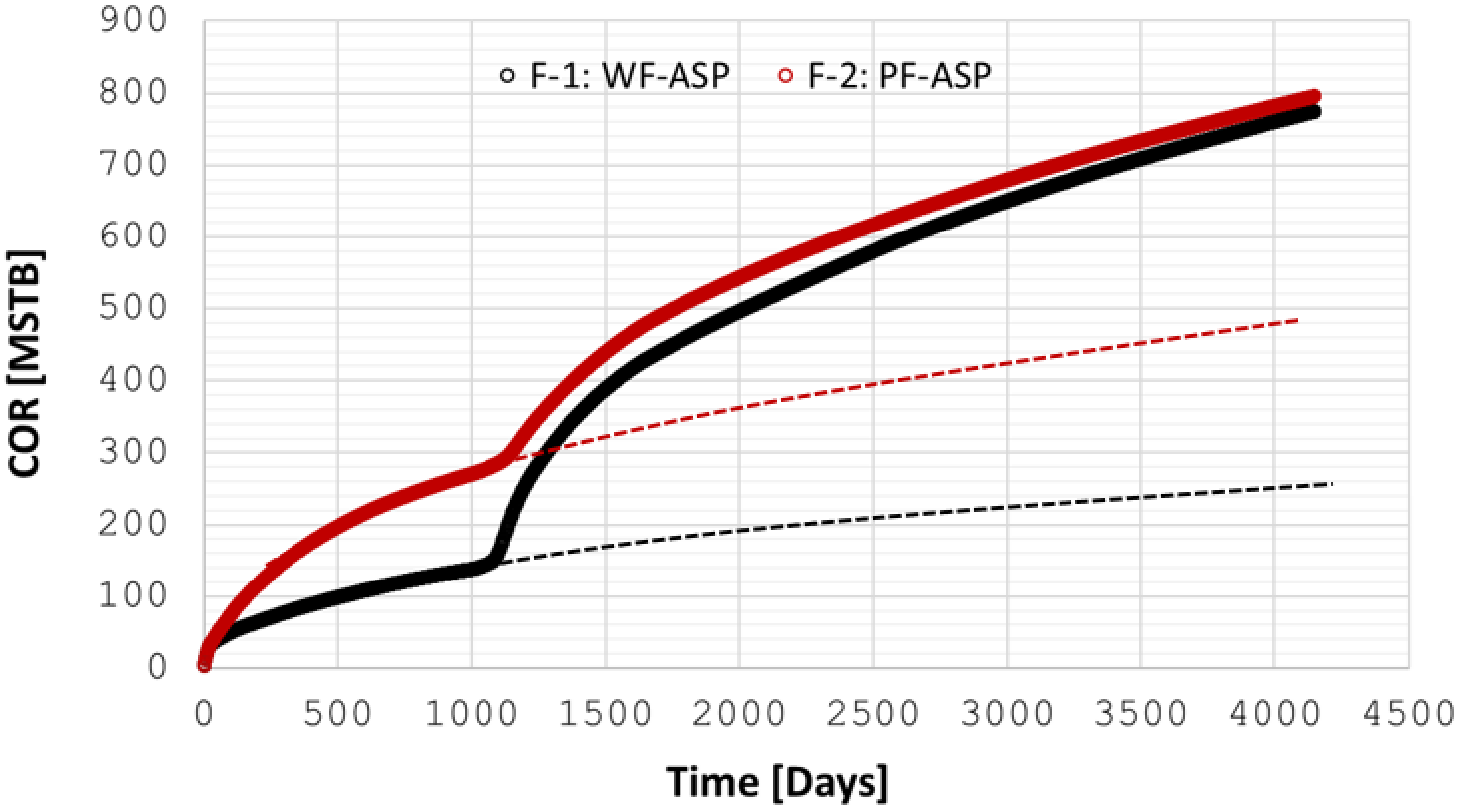


Fig. 7—Field model, Oil recovery is always higher with polymer flood before ASP flood (*F2;* grey) versus waterflood before ASP flood (*F1;* blue). Polymer flooding before (A)SP does not impede oil production and in fact enhances recovery due to conformance.

Conclusions

- Prolonged waterflooding gives the lowest Ultimate Recovery (UR) and has the lowest Present Value (PV) compared to the early implementation of EOR. It has the highest CO_2 footprint compared to the other methods.
- Polymer flooding has proven to be a cost-effective and robust EOR technique suitable for various field conditions. Therefore, it is the logical continuation of waterflood and addresses the sustainability issues of today
- Injecting polymer as early as possible improves UR and incremental PV. Operators should consider directly implementing a polymer flood while investigating the opportunity for Surfactant. Does not hinder performance of surfactant flood.
- Early (A)SP flooding yields the highest UR, PV, and Unit Technical Cost (UTC). However, it's important to note that this scenario is improbable since the risk is high and full-field implementation is impossible due to logistical issues. Reservoir uncertainties and operational difficulties might impact the results. ASP success requires experience, expertise and must be targeted at specific field areas.
- Operators can derive value and field experience from the polymer flood, allowing the identification of flow units for which (A)SP is valuable.
- Improving the understanding of the reservoir response/model under polymer flooding allows better identification of the most promising zones/areas that can be converted to (A)SP injection at lower risk and with a lower burden to logistics.
- Advantages in 2D and 3D floods, early injection of polymer redirects surfactant fluid leading to greater sweep and higher recovery. Improved conformance.