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A Critical Assessment of Several Reservoir Simulators for Modeling Chemical Enhanced Oil Recovery Processes

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Abstract

Interest in chemical enhanced oil recovery (CEOR) processes has intensified in recent years because of rising oil prices as well as the advancement in chemical formulations and injection techniques. Polymer (P), surfactant/polymer (SP), and alkaline/surfactant/polymer (ASP) are techniques for improving sweep and displacement efficiencies with the aim of improving oil production in both secondary and tertiary floods. Chemical flooding has much broader range of applicability than the past. These include high temperature reservoirs, formations with extreme salinity and hardness, naturally fractured carbonates, and sandstone reservoirs with heavy and viscous crude oils.

More oil reservoirs are reaching maturity where secondary polymer floods and tertiary surfactant methods have become increasingly important. This significance has added to the industry's interest in using reservoir simulator as a tool for reservoir evaluation and management to minimize costs and increase the process efficiency. Reservoir simulators with special features are needed to represent coupled chemical and physical processes present in CEOR processes. The simulators need to be first validated against well controlled lab and pilot scale experiments to have reliable predictions of the full field implementations.

The available data from laboratory scale include 1) phase behavior and rheological data, 2) results of secondary and tertiary coreflood experiments for P, SP, and ASP floods under reservoir conditions, i.e. chemical retentions, pressure drop, and oil recovery. Data collected from corefloods are used as benchmark tests comparing numerical reservoir simulators with CEOR modeling capabilities such as STARS of CMG, ECLIPSE-100 of Schlumberger, REVEAL of Petroleum Experts, and UTCHEM from The University of Texas at Austin. The research UTCHEM simulator is included since it has been the benchmark for chemical flooding simulation for over 25 years.

The results of this benchmark comparison will be utilized to improve chemical design for field-scale studies using commercial simulators. The benchmark tests illustrate the potential of commercial simulators for chemical flooding projects and provide a comprehensive table of strength and limitation of each simulator for a given CEOR process. Mechanistic simulations of chemical EOR processes will provide predictive capability and can aid in optimization of the field injection projects. The objective of this paper is not to compare the computational efficiency and solution algorithms and only focus on the process modeling comparison.

Introduction

Conventional recovery from oil reservoirs based on natural depletion by energy of fluid is referred to primary production. However, after pressure decline due to production, it is required to increase reservoir pressure by injecting water or gas as a secondary recovery. However, it is recognized that water flooding cannot mobilize viscous oils or droplets of original oil trapped in smaller pores due to capillary force especially in fractured carbonate reservoirs. Injected water will flow through fractures easily and residual oil will remain unswept in smaller pores. There can be further oil recovery after secondary by decreasing oil viscosity using thermal methods for heavy oil reservoirs or changing the wettability of the fluids with respect to rock or decreasing interfacial tension (IFT) between water and oil by chemicals added to the injection water such as surfactant or alkali. These methods are referred to as Enhanced Oil Recovery processes (Lake, 1989; Green and Willhite, 1998). In recent years chemical processes are considered as valuable EOR methods for mature depleted light oil conventional reservoirs, nonthermal recovery of viscous oils and fractured carbonate reservoirs using chemicals for wettability alteration (Delshad *et al.*, 2006; Darabi *et al.*, 2012).

Chemical EOR methods have been studied extensively in the lab and field tested for several decades. However, its application has been encouraging and more visible now. Because of great advances in recent years, many of the original issues and limitations hindering the application of chemical EOR no longer exist.

Different commercial reservoir simulators can be used for modeling these complex chemical EOR processes. In this paper, the performance of VIP and REVEAL for chemical processes will be discussed briefly but the main focus will be on CMG-STARS, ECLIPSE and UTCHEM due to their worldwide applications. The laboratory coreflood experiments are modeled and compared. Pandey *et al.* (2008) used CMG-STARS extensively to model coreflood experiments for better understanding of flow mechanisms during chemical flood and also generate parameters which will be used subsequently in field scale simulations. Morel *et al.* (2008) used ECLIPSE polymer module to perform feasibility study of polymer injection in the Dalia field and their studies demonstrated useful results about injectivity and additional oil recovery.

Reveal (Petroleum Experts, 2012) is a full field reservoir simulator from Petroleum Experts with capability for modeling surfactant phase behavior and also mobility control which includes both polymer and gel options. The surfactant module is similar to that in UTCHEM and can define different phase behavior (Type I, Type II, and Type III) based on salinities. Reveal has the capability of modeling polymer and several polymer-gel kinetics based on shear thinning behavior near wellbore. Reveal has options for permeability reduction, inaccessible pore volume, gelation of polymer and a cross-linker, and degradation. It also includes a foam model for increasing gas phase viscosity especially in heavy oil reservoirs.

VIP (Landmark, 2012), Landmark's reservoir simulation suite, beside its capability for thermal simulation of hot water and steam injection has capability for polymer flooding in black oil model. In this paper, we compare chemical models of UTCHEM (version 2011), CMG-STARS (version 2010), and ECLIPSE (version 2009) for polymer, Surfactant/polymer, and alkaline/surfactant/polymer floods.

Model Description

Polymer flood

Polymer flooding is used for improving mobility ratio for better sweep of the remaining bypassed mobile oil after primary and secondary recoveries. The purpose of adding polymer to the injected water is to increase water viscosity, and decrease water effective permeability. This will reduce the mobility ratio and better mobilize the original oil with more uniform displacement front. It is obvious that different parameters such as polymer concentration, viscosity, adsorption on rock minerals, permeability reduction, inaccessible pore volume, and etc. are key parameters for controlling an efficient polymer flood. Different simulators model these properties differently which is the focus of this paper.

Viscosity vs. polymer concentration: UTCHEM models polymer viscosity as a function of concentrations, salinity, and divalent cations (hardness) as shown below:

$$\mu_p^0 = \mu_w \left(1 + \left(A_{p1} C_{4\ell} + A_{p2} C_{4\ell}^2 + A_{p3} C_{4\ell}^3 \right) C_{SEP}^{S_p} \right), \quad (1)$$

where $C_{4\ell}$ is the polymer concentration in phase ℓ , μ_w is the water viscosity, C_{SEP} is effective salinity ($C_{SEP} = \frac{C_5 + \beta_p C_6}{C_1}$), S_p is a parameter for the effect of salinity, and A_{p1} , A_{p2} , A_{p3} are input parameters.

For CMG-STARS, the non-linear mixing rule is applied for calculating polymer viscosity as follows:

$$\ln \mu_p = f(x_a) \ln \mu_a + \frac{1-f(x_a)}{1-x_a} \sum_{i \neq a} x_i \ln \mu_i, \quad (2)$$

where x_a is the components mole fraction, $f(x_a)$ is the mixing function which depends on x_a and μ_a is component viscosity. The effect of salinity and hardness on polymer viscosity is not modeled.

The polymer viscosity in ECLIPSE (ECLIPSE Technical Manual, 2009) is modeled using an effective polymer viscosity $\mu_{p,eff}$ based on Todd-Longstaff model. The model includes both the effect of dispersion and fingering,

$$\mu_{p,eff} = \mu_m(C_p)^\omega \cdot \mu_p^{1-\omega}, \quad (3)$$

where $\mu_m(C_p)$ is polymer solution viscosity as an increasing function of polymer concentration (C_p), μ_p is the polymer viscosity at maximum polymer concentration (i.e. injected polymer viscosity) as an input parameter and ω is the Todd-Longstaff mixing input parameter. The model, however, lacks the effect of salinity and hardness on polymer viscosity.

Polymer adsorption: UTCHEM uses Langmuir isotherm for polymer adsorption and includes polymer concentration and salinity as shown below:

$$\hat{C}_4 = \frac{a_4(C_{41})}{1 + b_4 C_{41}}, \quad (4)$$

$$a_4 = (a_{41} + a_{42} C_{SEP}), \quad (5)$$

where C_{41} is the polymer concentration in the aqueous phase ℓ and the parameters a_{41} , a_{42} , and b_4 are model input.

CMG-STARS uses Langmuir isotherm to calculate polymer adsorption as a non-linear function of salinity and mole fraction of polymer in the aqueous phase,

$$ad = \frac{(tad1 + tad2 * xnacl) * ca}{(1 + tad3 * ca)}, \quad (6)$$

where $xnacl$ is the salinity, ca is the mole fraction of polymer in aqueous phase, and $tad1$, $tad2$, $tad3$ are input parameters.

Polymer adsorption in ECLIPSE is calculated using modified Langmuir function as

$$C_{ads} = \frac{aC^m}{1+bC}, \quad (7)$$

$$a = (a_1 + a_2 C_{SE}) \left(\frac{K_{ref}}{K} \right)^n, \quad (8)$$

where C is the polymer concentration, m is the exponent for concentration dependence, C_{SE} is the salinity, K is gridblock permeability, K_{ref} is the reference permeability, n is the exponent for permeability dependence, and a_1 , a_2 , b are the adsorption coefficients.

Polymer permeability reduction: Polymer can reduce the water effective permeability where degree of permeability reduction depends on polymer type, molecular weight, shear effects, and rock properties. The model used in UTCHEM is as follows:

$$R_k = 1 + \frac{(R_{k \max} - 1) b_{rk} C_{4\ell}}{1 + b_{rk} C_{4\ell}}, \quad (9)$$

$$R_{k \max} = \min \left\{ \left[1 - \frac{c_{rk} (A_{pl} C_{SEP}^{Sp})^{1/3}}{\left(\frac{\sqrt{k_x k_y}}{\phi} \right)^{1/2}} \right]^4, 10 \right\}, \quad (10)$$

where $C_{4\ell}$ is polymer concentration, $R_{k \max}$ is the maximum permeability reduction, $rkcut$, b_{rk} , and c_{rk} are input parameters where $rkcut$ is the maximum permeability reduction allowed.

For CMG-STARS, permeability reduction is related to adsorption or mechanical entrapment which can cause blockage or reduction in permeability as shown below:

$$AKW(I) = \frac{AK(I) k_{rw}}{RKW(I)}, \quad (11)$$

$$RKW = 1 + \frac{(RRFT - 1) AD(C, T)}{ADMAXT}, \quad (12)$$

where AK is permeability, $RRFT$ is the residual resistance factor, $AD(C, T)$ is the adsorption isotherm, and $ADMAXT$ is the maximum adsorption capacity of the rock.

ECLIPSE uses similar equation as

$$R_k = 1.0 + (RRF - 1) \frac{C_p^\alpha}{C_p^{\alpha \max}}, \quad (13)$$

where RRF , C_p^α , and $C_p^{\alpha \max}$ are the residual resistance, polymer adsorption, and maximum adsorption capacity of the rock for polymer in phase α .

Polymer Rheology: The viscosity of polymer decreases by increasing shear rate especially near the injection wellbore. At low shear rates, μ_p is independent of shear rate, however, at higher shear rates the viscosity is reduced and finally a second plateau value close to the water viscosity will be achieved (Lake, 1989). The relationship between polymer viscosity and shear rate in UTCHEM is modeled using Meter's equation (Meter and Bird, 1964) as follows:

$$\mu_p = \mu_w + \frac{\mu_p^0 - \mu_w}{1 + \left(\frac{\dot{\gamma}_{eq}}{\dot{\gamma}_{1/2}} \right)^{P_\alpha - 1}}, \quad (14)$$

where μ_p^0 is the polymer viscosity at low shear rate, $\dot{\gamma}_{1/2}$ is the shear rate at which the polymer viscosity is equal to average of μ_p^0 and μ_w , and $\dot{\gamma}_{eq}$ is the equivalent shear rate. Other option available in UTCHEM is unified viscosity model for shear thinning and shear thickening using Carreau's model (Delshad *et al.*, 2008). There is a correction for near wellbore where the fluid velocity is high (Li and Delshad, 2012).

For CMG-STARS, shear effect will be included in the tabular format which relates polymer viscosity to fluid velocity. The fluid velocity will be calculated based on Blake-Kozeny equation (Sorbie, 1991) as follows:

$$\dot{\gamma}_{eq} = \frac{\dot{\gamma}_c |u_\ell|}{\sqrt{k k_{rc} \phi S_\ell}}, \quad (15)$$

where $\dot{\gamma}_c$ is the shear rate coefficient which includes non-ideal effect such as slip and is equal to 4.8.

For ECLIPSE, there is a table to input the shear thinning or thickening polymer viscosity as a function of water velocity where,

$$V_w = b_w \cdot \frac{F_w}{\phi A}, \quad (16)$$

$$\mu_{sh} = \mu_{w,eff} \left[\frac{1 + (P-1)M}{P} \right], \quad (17)$$

where b_w is the water formation volume factor, F_w is water flow rate, A is the flow area between a pair of wells, $\mu_{w,eff}$ is the water viscosity, μ_{sh} is polymer shear viscosity, P , and M are viscosity thinning or thickening multipliers provided as input. Table 1 illustrates the important features of polymer module in each simulator.

Table 1: Comparison of polymer model options.

Polymer Module	UTCHEM	CMG-STARS	ECLIPSE
Viscosity vs. Polymer Conc.	✓	✓	✓
Viscosity vs. Shear Rate	✓	✓	✓
Adsorption	✓	✓	✓
Permeability Reduction	✓	✓	✓
Inaccessible Pore Volume	✓	✓	✓
Effect of Salinity on Viscosity and Adsorption	✓	Not Included	Not Included
Effect of Hardness on Viscosity, Adsorption, and Permeability Reduction	✓	Not Included	Not Included

Surfactant Flood

Oil droplets can be trapped because of microscopic capillary forces during water injection. This trapping can be shown as a competition between viscous forces to mobilize oil and capillary forces that cause trapping of oil (Lake, 1989). Surfactant injection into reservoirs for water/oil interfacial tension reduction was first performed by Uren and Fahmy (1927). IFT can be reduced from 30 dynes/cm in a typical waterflood to around 10^{-2} dynes/cm, which causes a significant reduction in residual oil saturation (Green and Willhite, 1998). Surfactant/polymer slug injection should be followed by polymer flooding. The main objective is to use low-cost, high performance surfactants with more innovative ways (Levitt, 2006; Adkins *et al.*, 2012). With the comprehensive understanding of the relationship between the surfactant structure and its performance, surfactant formulations are developed that give invaluable results even under high temperature and high salinity reservoirs (Solairaj *et al.*, 2012; Adkins *et al.*, 2012; Lu *et al.*, 2012). Lu *et al.* (2012) performed dynamic corefloods using new surfactant formulations at reservoir temperature and investigated the effect of surfactant formulation on IFT reduction and oil recovery.

Here we compare the surfactant models available in UTCHEM, CMG-STARS, and ECLIPSE.

Microemulsion Viscosity: Microemulsion (ME) is a thermodynamically stable mixture of water, oil, surfactant/ co-surfactant where at certain conditions of temperature, pressure, and salinity can form a separate phase. Viscosity of the ME phase is one of the key factors in the successful design of surfactant flood (Delshad, 1994). Viscous ME can cause plugging, lower injectivity, high retention, and low recovery. Microemulsion viscosity is a function of the composition. UTCHEM can model ME viscosity as a function of water, oil and surfactant concentrations in the ME phase as shown below:

$$\mu_{ME} = C_{13} \mu_w e^{[\alpha_1(C_{23}+C_{33})]} + C_{23} \mu_o e^{[\alpha_2(C_{13}+C_{33})]} + C_{33} \alpha_3 e^{[\alpha_4 C_{13} + \alpha_5 C_{33}]}, \quad (18)$$

where C_{13} , C_{23} , C_{33} are the water, oil and surfactant concentrations in the ME phase, and α_1 , α_2 , α_3 , α_4 , α_5 are input parameters. When polymer is added to the surfactant solution, water viscosity (μ_w) is replaced with the polymer solution viscosity μ_p^0 .

There is no option for ME phase or its viscosity in either CMG-STARS or ECLIPSE. It is assumed that surfactant solution has viscosity the same as that of the water.

Interfacial Tension: Interfacial tension and its reduction will be controlled by surfactant type, surfactant concentration, injected and formation salinity, as well as hardness, reservoir temperature, and crude oil composition (Green and Willhite, 1998). There exists a strong correlation between the phase behavior of a microemulsion system and IFT (Lake, 1989; Healy and Reed, 1974).

Both Healy and Reed (1974) and Chun Huh (1979) correlations are available in UTCHEM. Huh's correlation correlates IFT with oil solubilization ratio (R_{23}) as

$$\sigma_{23} = \frac{C}{R_{23}^2}, \quad (19)$$

$$R_{23} = \frac{C_{23}}{C_{33}}. \quad (20)$$

The implementation in UTCHEM includes a correction to ensure the IFT approaches oil/water in the absence of surfactant as follows:

$$\sigma_{l3} = \sigma_{ow} e^{-aR_{l3}} + \frac{CF_\ell}{R_{l3}^2} (1 - e^{-aR_{l3}^3}), \quad (21)$$

where σ_{ow} is the water/oil IFT, F_ℓ is the correction factor, and a is equal to about 10.

A table of IFT as a function of surfactant concentration is provided in both CMG-STARS and ECLIPSE.

Phase Behavior: The phase behavior of surfactant at reservoir conditions is very complicated due to many factors influencing its performance. Healy and Reed (1974) showed that the phase behavior strongly depends on brine salinity and there are essentially three different types of Type I, Type II, and Type III. The phase behavior model in UTCHEM is based on Hand's rule (Hand, 1939) and uses the ternary diagram for representing different microemulsion phases and tie lines which are distributive curves. The tie lines which join the composition of the equilibrium phases are given as

$$\frac{C_{3\ell}}{C_{2\ell}} = E \left(\frac{C_{3\ell}}{C_{1\ell}} \right)^F, \quad \text{for } \ell = 1, 2, \text{ or } 3 \quad (22)$$

where E and F are empirical parameters and ℓ refers to aqueous, oleic or microemulsion phase.

There is no ME phase in CMG-STARS and ECLIPSE and effect of salt on phase behavior is not modeled. However, there are two options to specify surfactant partitioning between phases in CMG-STARS. The first is irreversible which means surfactant cannot dissolve back into the water and second is reversible which indicates surfactant can dissolve back into water defined as K values for each component. In summary, Table 2 illustrates the key features in each simulator.

Table 2: Comparison of surfactant model options.

Surfactant Module	UTCHEM	CMG-STARS	ECLIPSE
ME Viscosity	✓	Not Included	Not Included
Interfacial Tension	✓	Included (Tabular Format)	Included (Tabular Format)
Phase Behavior	✓	Not Included	Not Included
Surfactant Adsorption	✓	✓	✓
Ion Exchange Effect	✓	✓	✓
Effective Salinity Window	✓	Not Included	Not Included

STARS-ME is a new version of STARS where microemulsion is defined as a separate phase similar to UTCHEM. In fact, gas phase is replaced by ME phase and three phases of water, oil, and ME exist. Phase behavior and relative permeability models are similar to UTCHEM. The minimum requirement for defining phase behavior is the determination of salinity limits for Type III and the height of the binodal curves at three salinity values.

Alkaline Flood

Alkaline-surfactant-polymer (ASP) flooding is just another version of the surfactant-polymer (SP) flooding process. It uses the surfactants or, sometimes, called petroleum soap generated in-situ from interactions between the alkaline chemicals injected and the in-place acidic components in the crude oil along with the injected surfactants to lower the interfacial tension between the chemical slug and the crude oil to increasing the capillary number and, therefore, lowering the residual oil saturation. The recovery mechanisms of the ASP process are similar to the SP process but interactions of the alkaline chemicals with the reservoir solids and crude oils are much more complex and may cause severe production problems such as the severe emulsions and scales. However, if we can take the advantage of the in-situ generated surfactants, the economic benefits in chemical costs could be substantial.

Both UTCHEM and STARS model geochemical reactions and consider the effect of in situ generated soap. Binodal curves for surfactant and soap phase behavior are defined using hand's rule. STARS supports IFT data in tabular format as explained before but IFT can be modeled using Chun Huh or Healy and Reed model in STARS-ME and tabular format is no longer supported in STARS-ME. It should be noted that polymer model in STARS-ME is the same as that in STARS. Relative permeability curves at high and low capillary number are given in input. The relative permeability is then interpolated as a function of capillary number. Four types of reactions (aqueous phase reactions, dissolution/precipitation reactions, ion exchange with clays reactions, and acid dissociation reactions) are defined and assumed to be in equilibrium.

The main advantage of STARS-ME is its ability in fast runtimes and parallel processing. The limitations are the lack of gas phase and the effect of buoyancy in the capillary number. STARS-ME is only limited to a total of 9 components with specific names for each component. This module is still under development and therefore we do not include in our benchmark study.

Results and Discussion

A) Polymer flood using UTCHEM and CMG-STARS

A Cartesian model was set up where single phase polymer flood is simulated. The injection was at constant rate and production was at constant pressure and different parameters of concentration, adsorption, shear rate, and etc. were evaluated. Table 3 gives the properties used for this comparison. The comparison of polymer viscosity model between UTCHEM and CMG-STARS is shown in Fig. 1. This part can be divided into two main case studies:

- a. Investigate polymer viscosity model and its impact on injection pressure and average pressure while the polymer adsorption and also viscosity dependency on shear rates are not included. A comparison of injection and average pressure is shown in Fig. 2. Overall the results are close considering very different models for viscosity as a function of concentration. Fig. 3 compares water viscosity distributions after 180 days.
- b. Same comparison as part (a) but polymer adsorption and shear effect are included. A comparison of injection and average pressure in Fig. 4 shows more differences compared to the previous case. Adsorption and shear rate models in UTCHEM use a function whereas CMG-STARS uses tables. The water viscosity profiles after 180 days are shown in Fig. 5.

Table 3: Properties of model used for comparison polymer model between UTCHEM and CMG-STARS.

Model	3-Dimensional Cartesian
No. of Grids	15×15×5
Porosity and permeability	0.19, 100 md
Water saturation	100 %
Injection Rate (constant rate)	561.5 ft ³ /day
Production Pressure (constant pressure)	1800 psi
Polymer Concentration	0.25 wt%
Simulation Time	1000 days

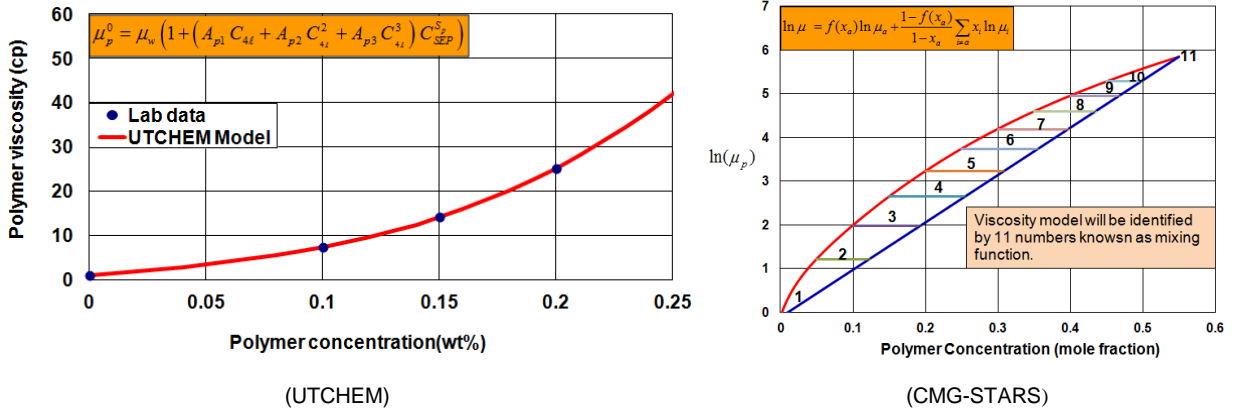


Fig. 1: Comparison of polymer viscosity model between UTCHEM and CMG-STARS.

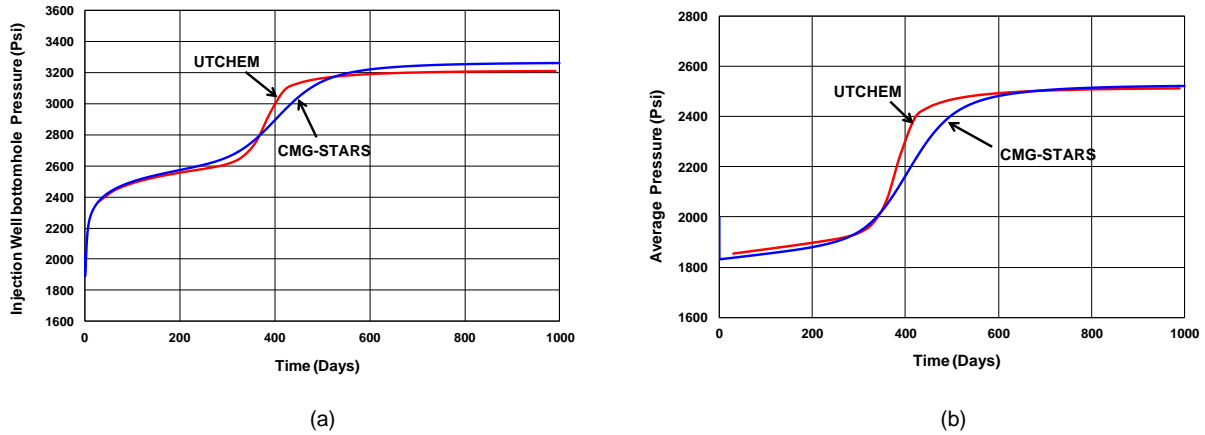


Fig. 2: Comparison of (a) injection pressure and (b) average pressure between UTCHEM and CMG-STARS for polymer model (Base case-No polymer adsorption and shear effect).

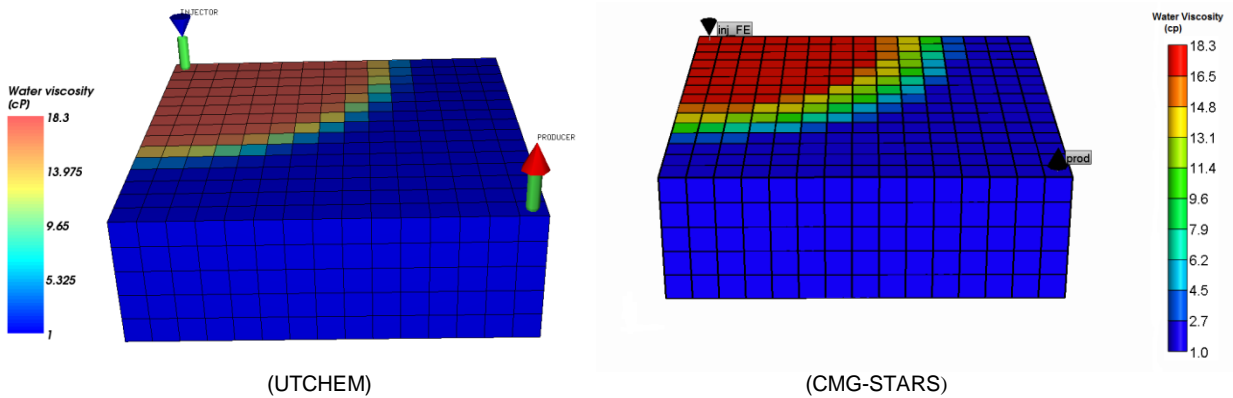


Fig. 3: Comparison of water viscosity profile between UTCHEM and CMG-STARS for polymer model (Base case-No polymer adsorption and shear effect).

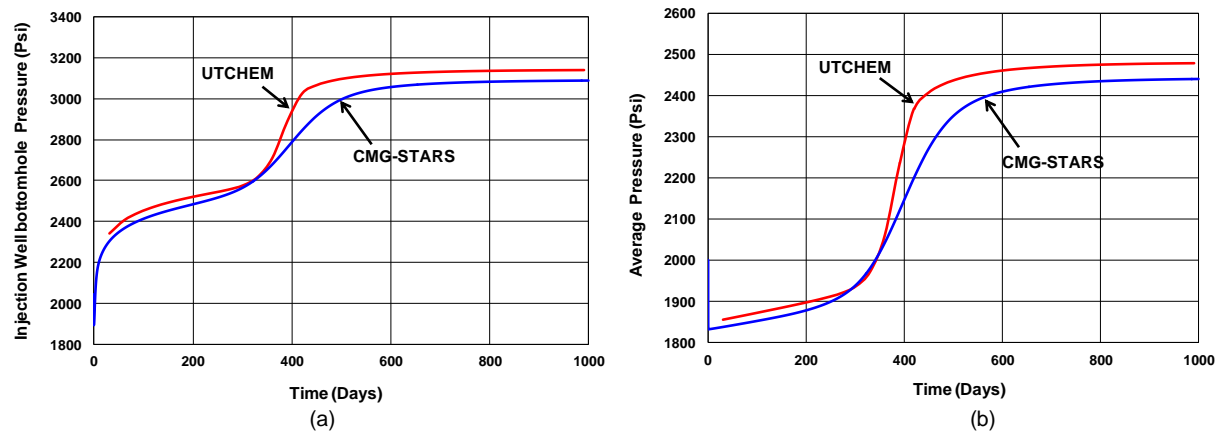


Fig. 4: Comparison of (a) injection pressure and (b) average pressure between UTCHEM and CMG-STARS for polymer model (Polymer adsorption and shear effect are included).

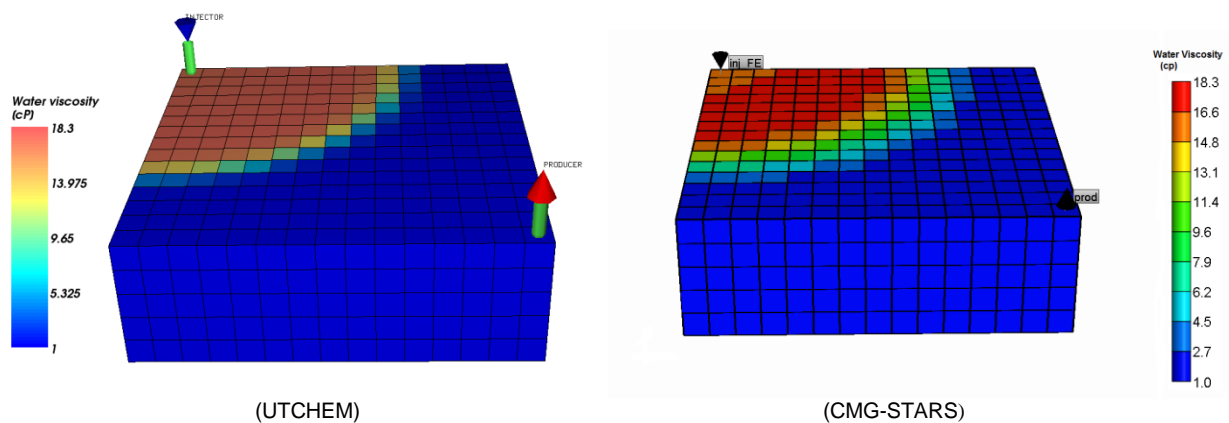


Fig. 5: Comparison of water viscosity between UTCHEM and CMG-STARS for polymer model (Polymer adsorption and shear effect are included).

B) Coreflood simulations using UTCHEM and CMG-STARS

Experimental procedure: Mohanty (2012) performed a coreflood experiment using outcrop Berea core with ASP formulation at ultralow IFT conditions. The reservoir dead oil was used for this experiment which was active oil with pH of around 8.5-9.5 when sodium carbonate was added and soap was generated insitu. First, the core was saturated with formation brine and then flooded with reservoir dead oil and left the core in the oven at reservoir temperature of 59 °C overnight. Then the core was flooded with 3 PVs of synthetic formation brine (SFB) from bottom at the velocity of 1 ft/d and then flooded with 2 PVs of SFB at the rate of 10 ft/d to reach residual oil saturation before the chemical flood starts. A water preflush was followed by ASP chemical slug, then polymer drive and finally by post water injection. Oil recovery was nearly 80%. A summary of rock properties and the main coreflood steps is shown in Table 4.

Table 4: Fluid and coreflood conditions.

Core ID	Berea Core
Diameter and Length	3.78 cm, 27.153 cm
Porosity, Permeability	0.18, 300 md
Initial oil Saturation	0.412
Irreducible Water Saturation	0.21
Surf. Concentration	0.5 wt%

Table 4 continued.

Oil Recovery	80 %OOIP
IFT	0.00062 mN/m
Temperature	59 °C
Crude Oil Viscosity	14 cp
Residual Oil Saturation	0.41
Duration of Coreflood Experiment	0.72 days
Chemical flood:	Pore volume injected:
<u>Preflush</u>	0.4 PV
0.5% Na ₂ CO ₃ , 1.1% NaCl in SFB	
<u>ASP Slug</u>	0.3 PV
0.5% surf., 0.25% polymer, 0.5% Na ₂ CO ₃ , 1.1% NaCl in SFB	
<u>Polymer Drive</u>	1 PV
0.25% polymer, 0.5% NaCl in SFB	
<u>Post Water Injection</u>	2 PV

Simulation Results: The objective of this section was to history match ASP coreflood using UTCHEM and CMG-STARS simulators, which provides the key parameters for field scale simulations. Surfactant phase behavior showed a solubilization ratio of around 22 at optimal salinity of 11,000 ppm. Based on Huh's correlation and using optimum solubilization ratio, a very low IFT of 0.00062 dynes/cm was calculated. CMG-STARS has no capability for alkali reactions but the effect of alkali is modeled on IFT and surfactant adsorption provided as input tables. A comparison of oil recoveries and oil saturations is shown in Fig. 6. Oil cut and pressure drop are compared in Fig. 7.

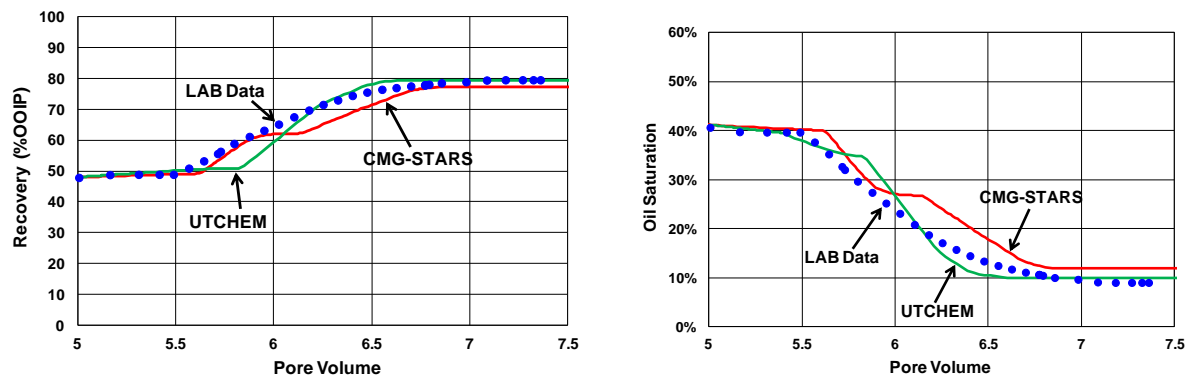


Fig. 6: Comparison of measured and simulated oil recovery and oil saturation.

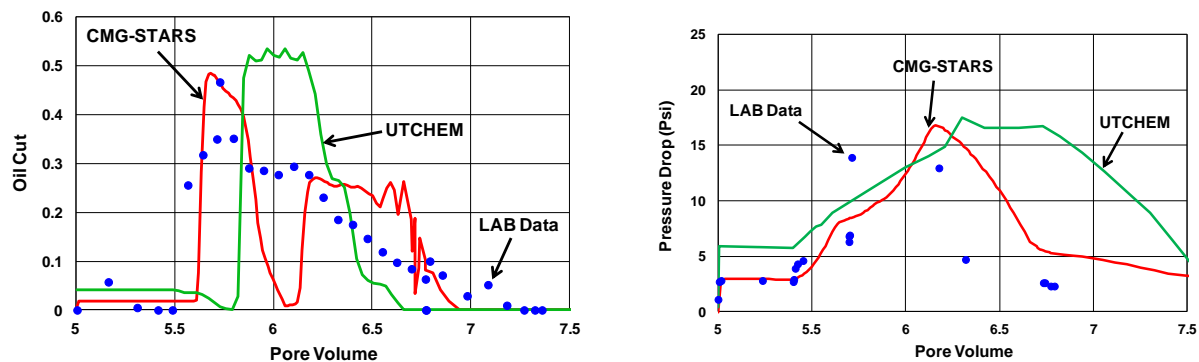


Fig. 7: Comparison of simulated and measured oil cut and pressure drop.

C) Polymer flood simulation using UTCHEM and ECLIPSE

UTCHEM and ECLIPSE are compared for polymer flood based on total oil production, production rate, oil saturation, and polymer concentration. A Cartesian model was set up with constant rate injection and constant pressure production. Table 5 gives the properties used for this comparison. The polymer models were defined for both ECLIPSE and UTCHEM as close as possible. The comparison of total oil production and oil production rate shows that there is good agreement between UTCHEM and ECLIPSE for polymer flood as Fig. 8 illustrates. Saturation profiles after 1000 days are very close (Fig. 9). However, it should be noted that ECLIPSE polymer viscosity model lacks the effect of salinity and hardness on viscosity, permeability reduction, and adsorption. There are differences between UTCHEM and ECLIPSE. Firstly, it should be noted that polymer concentration in UTCHEM varies from 0 to 0.15 weight percent, which is equivalent to values from 0 to 50 lb/stb in ECLIPSE. Secondly, the difference in polymer concentration profiles (Fig. 10) is because ECLIPSE shows the polymer concentration movement exactly as maximum injected concentration and does not consider the residual oil remained behind polymer front and has effect on polymer concentration, whereas, UTCHEM shows this reduction in polymer concentration which arises from oil and water concentrations left behind polymer flood. The profiles of water and oil concentrations after 1000 days from UTCHEM simulation are shown in Fig. 11.

Table 5: Polymer flood simulation data between UTCHEM and ECLIPSE.

Model	2-Dimensional Cartesian
No. of grids	10×10×1
$\Delta x, \Delta y, \Delta z$	75, 75, 30 ft
Porosity, Permeability	0.2, 50 md
Initial Water Saturation	25 %
Initial Reservoir Pressure	4000 psi
Oil Relative Permeability Endpoint	0.8
Water Relative Permeability Endpoint	0.25
Temperature	25 °C
Crude Oil Viscosity	2 cp
Residual Oil Saturation	0.3
Injection Rate (constant rate)	1123 ft ³ /day
Production Pressure (constant pressure)	3999 psi
Polymer Concentration	0.15 wt%
Simulation Time	1000 days

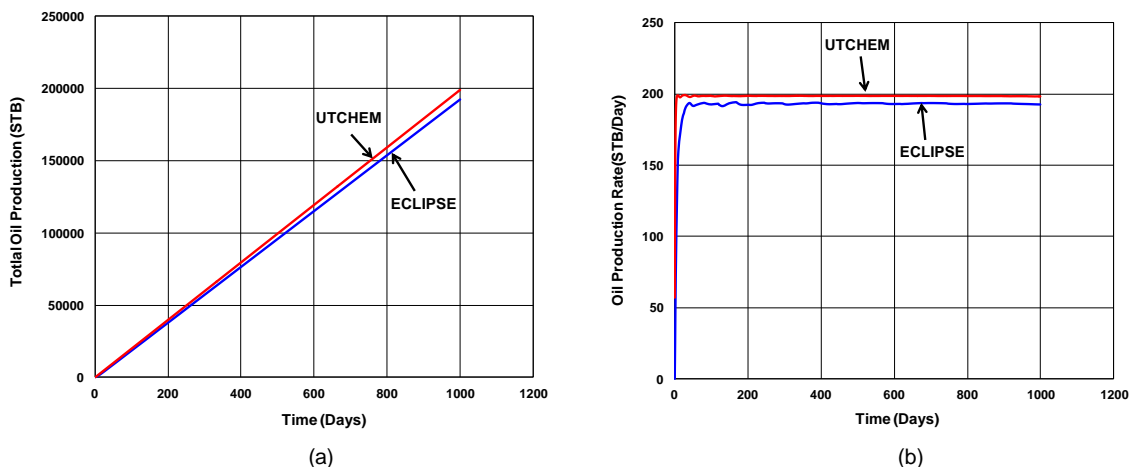


Fig. 8: Comparison of (a) total oil production and (b) oil production rate between UTCHEM and ECLIPSE for polymer flood.

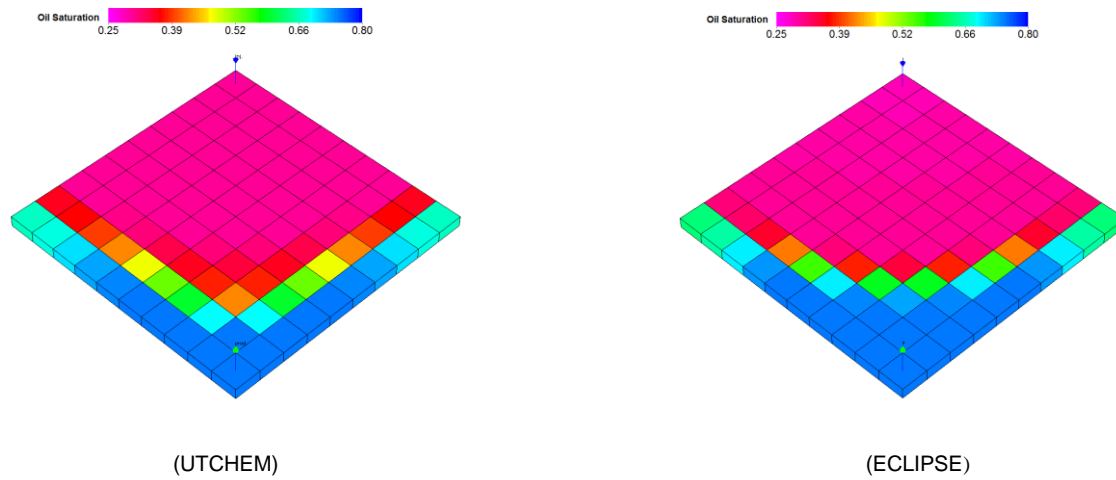


Fig. 9: Oil saturation profiles after 1000 days in UTCHEM and ECLIPSE for polymer flood.

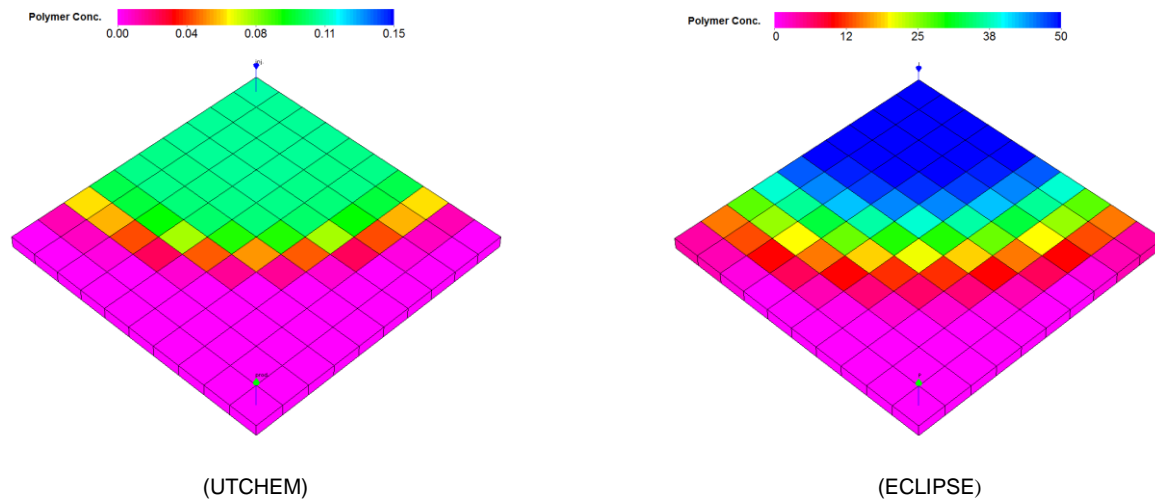


Fig. 10: Polymer concentration profiles after 1000 days in UTCHEM and ECLIPSE for polymer flood.

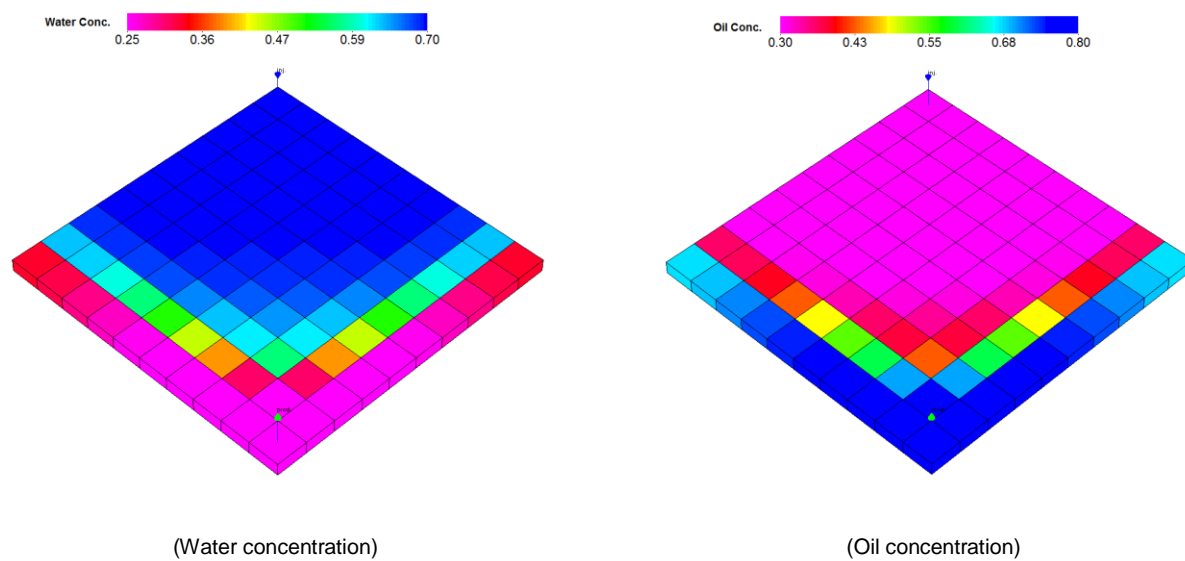


Fig. 11: Water and oil concentration profiles after 1000 days in UTCHEM for polymer flood.

D) Surfactant flood Simulation using UTCHEM and ECLIPSE

A sector model with $95 \times 192 \times 5$ gridblocks in X, Y, and Z directions is used for this exercise. Table 6 gives the reservoir and fluid properties. Average reservoir properties for each layer are given in Table 7. The reservoir is described as layered with two units separated by a hard streak barrier that limits the vertical flow between the units. Initially the reservoir was under primary depletion using the central well. The reservoir temperature is about 220°F and the initial reservoir pressure is 4000 psi at a reference depth of 6150 ft. The surfactant models were defined for both ECLIPSE and UTCHEM with an attempt to make the input as close as possible. The simulation was based on waterflood for 3980 days followed by surfactant flood for almost 5000 days. The comparison of surfactant injected and cumulative oil production shows that there is a good agreement between UTCHEM and ECLIPSE as Fig. 12 illustrates.

Table 6: Reservoir and fluid properties for surfactant flood using UTCHEM and ECLIPSE.

Model	3-Dimensional Cartesian
No. of grids	$95 \times 192 \times 5$
$\Delta x, \Delta y$	40, 50 ft
Initial Reservoir Pressure	4000 psi
Oil Relative Permeability Endpoint	1.0
Water Relative Permeability Endpoint	0.23
Temperature	105°C
Crude Oil Viscosity	2 cp
Water Viscosity	0.8 cp
Surfactant Concentration	0.017 %
Simulation Time	8705 days

Table 7: Averaged properties per layer.

Layer	K_x, md	K_y, md	K_z, md	ϕ	$\Delta z, \text{ft}$	S_{wi}
1	3.264	9.806	1.634	0.17393	1.61	0.172
2	4.453	13.358	2.226	0.1694	1.61	0.162
3	1.489	4.466	0.744	0.25714	1.8	0.393
4	1.188	3.564	0.594	0.17344	1.8	0.381
5	0.712	2.136	0.356	0.1187	1.8	0.424

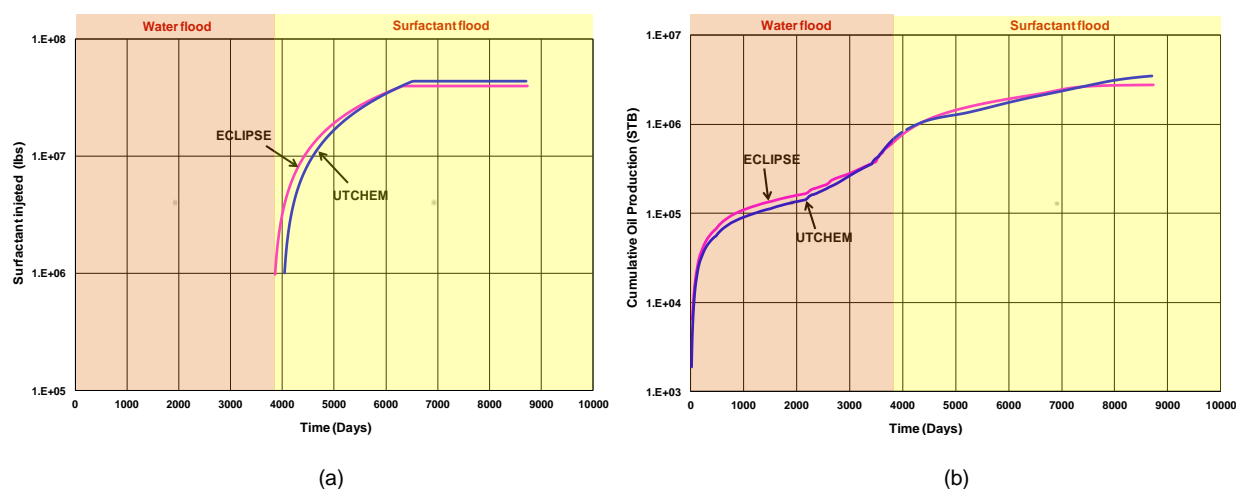


Fig. 12: Comparison of (a) surfactant injected and (b) cumulative oil production between UTCHEM and ECLIPSE for water-surfactant flood.

The summary and conclusion for this work are presented in the following:

- Careful selection of tables in the commercial simulators against UTCHEM correlations leads to a reasonable agreement for different chemical EOR applications.
- Laboratory coreflood results were history matched using UTCHEM and CMG-STARS with very good agreement.
- Polymer models were compared between UTCHEM and CMG-STARS and also between UTCHEM and ECLIPSE. The results showed differences because of different viscosity models in each software.
- The effect of salinity and hardness in polymer model is not considered in either CMG-STARS or ECLIPSE.
- UTCHEM results show a reduction in polymer viscosity as expected when adsorption and subsequent reduction in polymer concentration is modeled, However, CMG-STARS and ECLIPSE give no considerable effect on polymer viscosity compared to the case with no adsorption.
- The surfactant flood for a large field scale case was modeled using both UTCHEM and ECLIPSE and fairly close results were achieved. Tables for ECLIPSE were generated based on UTCHEM correlations. Water viscosity was replaced with microemulsion viscosity in order to achieve a good comparison.

Nomenclature

A	Flow area
A_{p1}, A_{p2}, A_{p3}	Matching parameters for UTCHEM polymer viscosity model
a_{41}, a_{42}, b_4	Polymer adsorption parameters in UTCHEM
a_1, a_2, b	Polymer adsorption parameters in ECLIPSE
$AD(C,T)$	Adsorption isotherm of polymer in CMG-STARS
$ADMAXT$	Maximum adsorption capacity of the rock in CMG-STARS
B_w	Water formation volume factor
b_{rk}, c_{rk}	Permeability reduction parameters in UTCHEM
C	Polymer concentration in ECLIPSE
ca	Mole fraction of polymer in aqueous phase for CMG-STARS
C_p	Polymer concentration in ECLIPSE
C_{13}	Water concentration in ME phase
C_{23}	Oil concentration in ME phase
C_{33}	Surfactant concentration in ME phase
$C_{4\ell}$	Polymer concentration in phase l
C_5	Total anions concentration in UTCHEM
C_6	Divalent cations in UTCHEM
C_p^α	Polymer adsorption in phase α for ECLIPSE
$C_p^{\alpha\max}$	Maximum polymer adsorption in phase α for ECLIPSE
C_{SE}	Salinity in ECLIPSE
C_{SEP}	Parameter for salinity effect on polymer viscosity
E, F	Empirical parameters for surfactant phase behavior in UTCHEM
F_w	Water flow rate in ECLIPSE
$f(x_a)$	Mixing function for polymer viscosity in CMG-STARS
K	Grid block permeability
K_{ref}	Reference permeability
m	Exponent for concentration dependency of polymer viscosity in ECLIPSE

M	Viscosity thickening or thinning multiplier in ECLIPSE
n	Exponent for permeability dependency in ECLIPSE
P	Viscosity thickening or thinning multiplier in ECLIPSE
$R_{k_{max}}$	Permeability reduction for polymer in UTCHEM
RRF	Residual resistance factor in ECLIPSE
R_{23}	Oil solubilization ratio
S_l	Liquid saturation
S_p	Parameter for divalent cation effect on polymer viscosity
$tad1, tad2, tad3$	Polymer adsorption matching parameters in CMG-STARS
x_a	Component mole fraction
$xnacl$	Salinity in CMG-STARS
μ_w	Water viscosity
μ_a	Component viscosity
$\mu_m(C_p)$	Mixed polymer solution viscosity in ECLIPSE
μ_{ME}	ME Viscosity
μ_p	Polymer viscosity at maximum polymer concentration
μ_{sh}	Shear polymer viscosity in ECLIPSE
$\dot{\gamma}_c$	Shear rate coefficient in CMG-STARS
$\dot{\gamma}_{eq}$	Equivalent shear rate in UTCHEM and CMG-STARS
σ_{23}	Oil/ME interfacial tension
σ_{ow}	Water/Oil interfacial tension
$\alpha_1, \alpha_2, \alpha_3, \alpha_4, \alpha_5$	Matching parameters for ME viscosity in UTCHEM
ϕ	Porosity
ω	Todd-Longstaff mixing parameter for polymer viscosity in ECLIPSE

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