SPE-196055-MS

Numerical Investigation of EOR Applications in Unconventional Liquid Reservoirs through Surfactant-Assisted Spontaneous Imbibition SASI and Gas Injection Following Primary Depletion

Fan Zhang, I. W. R. Saputra, Imad A. Adel, and David S. Schechter, Texas A&M University

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Calgary, Alberta, Canada, 30 Sep - 2 October 2019.

Abstract

Surfactant-Assisted Spontaneous Imbibition (SASI) and gas injection have been proven to improve production from Unconventional Liquid Reservoirs (ULR). However, the novelty of the method has resulted in a few publications to date. This study utilizes numerical modeling to upscale laboratory data of SASI for completion purposes and gas injection plus SASI for EOR. Novel gas and aqueous-phase injection strategies following primary depletion are designed based on actual completion and production data. Multiple sequencing configurations for both surfactant and gas injection are tested to propose the best combined-EOR scheme for ULR.

Parameters related to the mechanism of SASI and gas injection are retrieved from CT-generated core-scale model of laboratory experiments. SASI and gas injection experimental results were upscaled to model production response of a hydraulically fractured well with realistic fracture geometry and conductivity. The core-scale model was created to determine the diffusion coefficient, relative permeability, and capillary pressure curves by history-matching the laboratory data. The field-scale model was developed with a dual-porosity compositional model to predict production enhancement for various combined-EOR schemes in ULR.

Wettability and IFT alteration are the two primary mechanisms for SASI in enhancing production. Experimental studies revealed that surfactant solution recovered up to 30% OOIP, whereas water alone only recovered approximately 10% OOIP. Capillary pressure and relative permeability constructed from scaling group analysis and core-scale numerical models showed that surfactant addition enhances the two curves. On the other hand, gas injection EOR was found to be driven by multi-contact miscibility and diffusion. Parameters related to both methods were applied to the field-scale model for multiple completion and EOR schemes. Results demonstrate that the combination of SASI and gas injection possesses significant potential in improving production rates and estimated ultimate recoveries (EUR) in ULR. Soak times, surfactant concentration, injection pressure, duration of the cycle, and cumulative gas injection control the level of enhancement. With a large number of control variables, specific customizations can be optimized to suit criteria of different field applications.

Introduction

Unconventional liquid reservoirs (ULR) are characterized by low porosity and ultra-low permeability. During completion treatments, hydraulic fractures interact with natural fractures to create sufficient flow paths that assist with the extraction of the oil from the matrix and the production from shale reservoirs (Afra et al. 2019; Bao and Gildin 2017; Bao et al. 2017; Deng and King 2018; Kou et al. 2018). Due to the revolution of horizontal drilling along with multi-stage hydraulic fracturing, oil production from the ULR brought the United States to be the largest oil producer worldwide (Tang et al. 2017; Tang et al. 2018; Zhang and Zhu 2017, 2019; Zhu et al. 2018). The top three of the most prolific shale formations are the Wolfcamp formation in the Permian Basin, West Texas, the Bakken formation in the Williston Basin, North Dakota, and the Eagle Ford formation located in the Western Gulf Basin. Although a significant volume of hydrocarbons has been produced from theses unconventional liquid reservoirs, the ultimate recovery factor is typically deficient and is less than 10% of the original oil in place (OOIP). Therefore, it is necessary to understand different fluid transport mechanisms between the fracture networks and the matrix, as well as the possible implementation of enhanced oil recovery (EOR) techniques to oil production in shale reservoirs.

These resources are characterized by a fast decline curve and low recovery factors. Typically, the oil production rate decreases to less than 20% of the initial production, and more than half of the 5-year cumulative oil production is usually produced within the first year (Alvarez et al. 2017b; Pan et al. 2019; Xue et al. 2018; Yang et al. 2017; Yang et al. 2018). Shale reservoirs still possess more than 90% of the OOIP in the matrix after primary depletion. The vast abundance of oil still available in the reservoir makes the application of EOR really appealing, especially with the plentiful number of produced wells. Laboratory experimental results, along with field observations, have revealed the potential of EOR techniques in ULR. Gas injection EOR, chemical EOR, and thermal EOR have been widely applied in the petroleum industry in conventional reservoirs. For unconventional reservoirs, EOR techniques (gas injection and surfactant EOR) still need to be investigated more in order to understand the mechanisms and limitation of the field applications.

Surfactant-Assisted Spontaneous Imbibition (SASI) and gas injection EOR techniques have been observed as a significant potential to enhance oil production in unconventional liquid reservoirs. Several researchers investigated the effectiveness of the SASI EOR technique in ULR through laboratory experiments and numerical simulation (Alhashim et al. 2019; Alvarez et al. 2017a; Saputra and Schechter 2018; Zhang et al. 2018b). Core plugs from different formations (Wolfcamp, Eagle Ford, and Bakken) have been studied through spontaneous imbibition experiments. The addition of surfactant into the aqueous phase results in increased oil recovery from core plugs due to wettability alteration and interfacial tension (IFT) reduction. Surfactant molecules form a double layer on the rock surface, which alters the wettability of rock from oil-wet to water-wet and consequently leading the water to imbibe into the matrix and expelled the oil out from the matrix spontaneously. Additionally, there are several publications available on the evaluation of surfactant EOR in stimulation fluid through numerical simulation and upscaling laboratory results of SASI experiments to the field scale through analytical methods and numerical simulation. Gas injection EOR has also been widely studied through laboratory experiments and numerical simulation using different gases. Several researchers investigated the potential of gas injection EOR through Huff-n-Puff experiments (Adel et al. 2018a; Adel et al. 2018b; Tovar et al. 2018a; Zou and Schechter 2017). Typically, there are two types of gas injection experiments performed to study the potential of gas injection in the ULR, which are continuous gas flooding experiment and Huff-n-Puff experiments. Due to the low porosity and ultra-low permeability of shale reservoirs, Huff-n-Puff experiments have always been found to present a better performance when compared to the gas flooding experiment. The mechanisms of gas injection EOR in the ULR are Multi-Contact Miscibility (MCM) and diffusion. The soak period supports the dynamic process of recovering more oil from shale core plugs. Compared to other gases (lean gas, rich gas, and N_2), CO_2 presents the best potential as an EOR agent to enhance oil recovery from shale core plugs. In addition, investigations of gas injection EOR in the field-scale though numerical simulation are also available from the literature. Injection pressure and injection volume of the gas are the dominant parameters for gas injection EOR in the ULR. Results of gas injection simulation studies are consistent with laboratory observation that gas injection could significantly enhance oil production in shale reservoir. Recently, researchers have started to investigate combined EOR technologies to achieve optimum oil production in the unconventional liquid reservoirs. Zhang investigated the hybrid EOR technique combining gas injection EOR and SASI EOR through laboratory experiments. Additional oil can be recovered from the hybrid EOR technique when compared to individual gas injection EOR and SASI EOR, which opens the door to optimize oil production in the shale reservoirs through combined EOR techniques.

Oil production enhancement from the gas injection is governed by injection pressure, injection volume, and composition of the injected gas. The mechanisms of gas injection EOR are multi-contact miscibility, diffusion, and oil swelling. Minimum miscibility pressure (MMP) is a crucial parameter to be determined in any gas injection project. Typically, the recovery factor of gas injection at pressures below the MMP is less than 5%. Increasing the injection pressure always results in additional oil recovery from the matrix, especially at pressures beyond the MMP. The mechanism of gas injection EOR in the unconventional reservoir is different than in conventional reservoirs, resulting in a main departure from the conventional paradigm that injection pressure at the MMP is sufficient to achieve maximum oil recovery during the gas injection process. During the soak period in the Huff-n-Puff process, lighter and intermediate components of hydrocarbons are vaporized into the gas phase, and the gas is also dissolved into the oil, which results in oil extraction from the matrix. As gas is being dissolved into the oil phase, the oil swells and leads to additional oil is produced from the matrix. To evaluate the impact of the gas injection process in shale oil production, we selected the numerical simulation approach to study gas injection well performance. Numerical simulation is an economical approach to provide reasonable preliminary estimations and to optimize different parameters before testing the pilot well that can be very expensive. The diffusion coefficient is the only parameter that can be tuned to present the effect of gas injection EOR using the simulator. An explanation of how the primary mechanism of gas injection EOR is incorporated as part of the diffusion coefficient in the simulator will also be discussed.

Wettability of the rock surface is commonly determined by the affinity of oil or water to spread on the rock surface. The fluid with a higher affinity toward the rock surface is the wetting phase, and the fluid repelled from the surface is the non-wetting phase. Due to the amphiphilic nature of surfactants, surfactant molecules form a double layer on the rock surface to change the wettability from oil-wet to water-wet. Wettability alteration results in water imbibition into the matrix and oil production out of the matrix. In addition, surfactant addition also results in the reduction of interfacial tension. Previous study has shown that interfacial tension failed to correlate with recovery factors from laboratory-scale SASI experiments. However, interfacial tension reduction results in the enhancement of oil relative permeability curve, which means that relative permeability of oil is enhanced by surfactant additives. Both wettability alteration and interfacial tension reduction lead to oil production enhancement in ULR.

Both SASI EOR and gas injection EOR techniques present a great potential to enhance oil recovery in unconventional liquid reservoirs. To figure out whether these two EOR techniques can work together and further increase the ultimate oil recovery of a shale oil well. Hybrid EOR experiments were performed on Eagle Ford core plugs. The saturated core plugs were the first subject to multi-cycle gas injection experiments until ultimate recovery was achieved. SASI experiments were immediately performed on the core plugs after they have gone through the gas injection experiment. Results of hybrid experiments demonstrate that lighter and intermediate components of the oil are recovered on the gas injection experiments from the larger pores of the rock; while the heavier components of the oil are produced during the spontaneous imbibition experiments from the smaller pores. The sequence of hybrid EOR experiments is determined by the average recovery factor from the SASI and gas injection experiments. Typically, the recovery factor of the gas injection experiment is higher than SASI experiment. However, additional oil was recovered through the SASI experiment from the core plugs that have already been depleted from gas experiments. SASI following the gas injection experiments provides evidence that additional; oil can be produced by combining the two EOR techniques. Due to the different mechanism of SASI and gas injection EOR, the two EOR techniques can work together to achieve optimum oil production by targetting different spectrums of the oil composition and pore sizes from each technique.

In this study, the mechanisms of gas injection EOR, SASI EOR, and Hybrid EOR are investigated through analysis of experimental results, and numerical simulation. Complete and systematic SASI EOR, gas injection EOR, and hybrid EOR simulation workflow were developed to understand the mechanisms and evaluate the effect of oil production enhancement from all three EOR techniques in ULR. The first step for these studies is developing the core-scale simulation model using CT-scan technology to history-match laboratory data from the hybrid EOR experiments. Capillary pressure, relative permeability, and diffusion coefficient are determined from the history match results and implemented in the field-scale model. Then, the field-scale model is constructed by incorporating hydraulic fracturing simulation results, laboratory data, and core-scale history match results and is then validated by history matching the actual well production data. Finally, an investigation is provided on four different combined EOR scenarios using the field-scale model, which consist of 1. SASI EOR in the completion and gas injection EOR after primary depletion; 2, SASI injection EOR following gas injection EOR after primary depletion; 3. Gas injection EOR following SASI injection EOR after primary depletion; 4. Multi-cycle gas injection and SASI injection after primary depletion.

Methodology

The field-scale impact of hybrid EOR techniques is investigated through the utilization of a numerical model upscaling method. Numerical models are constructed based on the behavior observed on laboratory experiments provided on previous publication in order to accurately represent the physic behind the improvement of oil recovery (Zhang et al. 2018a). A summary of the laboratory experiment this study is based on will be provided first. Then, a discussion on the mechanisms that are believed to occur in the process of EOR involving both surfactant and gas molecules will be presented. Finally, the approach used in this study in incorporating the explained mechanism on both laboratory-scale and field-scale numerical models is presented along with a summary of reservoir properties included in the model.

Hybrid EOR Experimental Data

It is of high importance to understand the methodology of each experiment in order to provide a complete comprehension required for constructing a numerical model of the hybrid EOR process. A range of surfactant, gas, oil, water, rock characterization methods was included in the laboratory study. Interaction of oil, water, and surfactant was studied through the measurement of oil-water interfacial tension. Wettability of both initial and altered condition was analyzed using the captive bubble method. On the characterization of oil and gas interaction, minimum miscibility pressure was determined through the slim tube experiment. After the characterization process, the ultimate test on the efficacy of gas and surfactant in recovering oil from sidewall shale core plugs was carried. A core-flooding system for huff-n-puff experiments was used to study the performance of the injected gas, while spontaneous imbibition on a modified Amott cell was executed to assess the surfactant efficacy following the gas experiments. Computed Tomography (CT) scan of each experiment was also included to analyze the fluids interactions better and flow and to better characterize the recovery mechanisms.

Interfacial tension (IFT) of oil and water was measured on a Dataphysics OCA100 Pro under inversed pendant drop method. A transparent square cuvette is filled with the aqueous-phase and brought up to reservoir temperature by a heating table. Then a 0.52 mm-OD J-shaped needle with an electronically-controlled syringe on top is submerged into the heated solution. An oil drop is dispensed slowly, and a snapshot of the oil drop at its possible maximum volume is captured. IFT is then measured on the corresponding snapshot utilizing the built-in software. Density data of both fluids at the measurement temperature is measured before-hand and supplied into the software. The same process is performed on both the base case where the surfactant is not added to the solution and the surfactant solution case with a concentration of 2 gpt of the tested surfactant.

Wettability was analyzed through the captive bubble method instead of a sessile drop. This method was chosen as it assesses the interaction between the three phases in the reservoir, oil/water/rock, in one evaluation. In contrast, the sessile drop method is usually done with air as the ambient phase with either oleic- or aqueous-phase as the drop. The contact angle measurement is carried on the identical Dataphysics OCA 100 Pro as used on the IFT analysis. A rock sample stage is placed inside the cuvette containing the already heated aqueous-phase. This sample stage allows for access to the bottom surface of the rock where the oil drop will be placed using the J-shaped needle. A snapshot of the oil drop is then analyzed, the angle is measured through the aqueous phase, and the average angle of the left and right angle is reported. The system is considered oil-wet when the contact angle is above 90° and water-wet when the angle is below 90°. It is also important to note that the rock samples used in this measurement were processed before-hand. Several chips were taken from the sidewall core plug and cleaned by toluene, methanol, and vacuum-dried. Then, the rock chips were aged in their corresponding oil at reservoir temperature for at least two weeks to restore the reservoir wettability.

The MMP is the minimum pressure that the injected gas is miscible with the oil through the multi-contact process in the reservoir. It is the most critical parameter to be determined in any gas injection EOR project. The slim tube method is proven as the most accurate method to estimate the MMP. Although the slim tube method is very time consuming, we determined the MMP using the slim tube method to understand the mechanism of gas injection EOR better. The slim tube method simulates the 1-D displacement of the oil by the injected gas through porous media, accounting for the thermodynamics and phase behaviors happening during the gas-oil interactions. An 80 ft slim tube coil was used to determine the MMP of the CO_2-Eagle Ford oil system. A stainless steel coil with 0.25 in inside diameter and 0.063 in thickness is packed with 100-150 mesh sand to perform the MMP determination experiments. The schematic of the MMP experiment and further details are available in (Adel et al. 2016; Adel et al. 2018a).

In order to accurately calculate the recovery factor, core plugs are prepared following a robust preparation and re-saturation workflow. Core plugs are first cleaned using Dean-Stark technology and dried into a vacuum oven for 10 days. The dry and clean core plugs are then resaturated with their corresponding crude oil in a pressure vessel at 10,000 psi for more than three months to restore the cores to their original reservoir conditions.

The gas injection experiments were performed inside a core holder at reservoir temperature, which is 170 °F for the Eagle Ford formation. The re-saturated core plug is placed in the center of the core holder and surrounded by glass beads. This design is used as a physical simulation of the hydraulic fracture and matrix systems. The core holder is assembled inside a CT scanner in order to examine the fluid movement during the gas injection experiments. The experimental system is heated up to reservoir temperature using a water bath, and the system is then vacuumed. CO_2 is injected into the core holder and is allowed to soak for 10 hours. The soaked gas is then displaced with fresh gas at a constant flow rate over 3 hours. Oil is then collected from the outlet of the core holder, and the oil recovery is recorded by the end of each Huff-n-Puff cycle. The Huff-n-puff cycle is repeated until no more oil is recovered from the core plug. Further details and the schematic of the gas injection experiment is available in (Adel et al. 2018a; Tovar et al. 2018b).

Spontaneous imbibition experiments are the last set of measurement included in the study. This experiment serves as the ultimate appraisal of surfactant efficacy in producing oil from the shale samples. Spontaneous imbibition experiment by no means is novel. The experiment is usually carried in an Amott cell where a core plug is submerged for several days with the whole system placed inside an oven for temperature control. A pressure difference is not applied to the rock sample for the spontaneous imbibition experiment with the system pressure is set at atmospheric pressure. The Amott cell apparatus contains a graduated cylinder at its top to enable the quantification of oil that is being produced throughout the experiment time. For this study, spontaneous imbibition experiment is executed on the core plugs that have gone through the gas huff-n-puff experiment as previously described. Spontaneous imbibition experiment is conducted for 10 days at the same reservoir temperature used throughout the experimental assessment.

SASI EOR Mechanism

Production enhancement from SASI EOR is generated by the surfactant-driven alteration of capillary force in the oil/water/rock system. The presence of surfactant in the oil/water/rock system results in two most noticeable effects, the reduction of IFT and the alteration of wettability from oil-wet to water-wet. Both effects result in the alteration of capillary force as shown by the Young-Laplace equation given below. Reduction of IFT, represented as y, causes a decrease in capillary pressure. While the alteration of wettability, which is included in the form of contact angle, triggered the shift of capillary pressure from the negative region to the positive region. As mentioned previously, the contact angle of larger than 90° indicates an oil-wet surface while the water-wet surface is indicated by a contact angle below 90°. Under the Young-Laplace equation, then it can be observed that the oil-wet surface has negative capillary pressure and water-wet surface results in positive value capillary pressure. The shift from negative to positive capillary pressure is an essential effect from the addition of surfactant as it allows for capillary pressure to contribute to enhancing the oil expulsion from the rock pores.

$$P_c = \frac{2\,\sigma\,\cos\theta}{r} \tag{1}$$

Surfactant-driven wettability alteration is highly crucial in SASI EOR due to the capillary pressure shift it causes. Capillary pressure from an oil-wet surface, which initially prohibits oil production from occurring is transformed to provide additional force to enhance the production of oil. Therefore, it is essential to understand the mechanism behind the wettability alteration in order to include the phenomena in the model. Several authors have provided a meticulous experiment of which the relation of surfactant adsorption and wettability alteration is observed in (Saputra and Schechter 2018). The study predicted that on an oil-wet surface, the hydrophobic tail of the surfactant molecule attaches to the surface with the hydrophilic head facing the pore space. In the end, a layer of the hydrophilic head is formed, and the previously oil-wet surface is now a water-wet surface. The observed relation between the amount of surfactant adsorbed and wettability provides evidence of the possibility of this mechanism.

In summary, the presence of surfactant in the oil/water/system profoundly alters the capillary pressure. In response, capillary pressure alteration must be included in the model to be able to model the effect of surfactant on the reservoir. For this study, the capillary pressure curve is the main aspect to be controlled in order to model SASI EOR. Two curves will be given to each grid of the model, the initial curve of which surfactant is not present in the system and the final altered curve after contact with surfactant. The system will use the initial curve at the start of the simulation as surfactant has not encroached into the grid yet. Then on each time step when surfactant exists in each grid, a new capillary pressure curve is calculated by interpolating the new curve between the initial and final capillary pressure curves. The interpolation is weighted by the amount of surfactant adsorbed in each corresponding grid on each time step. Using the new capillary pressure curve, then a new capillary equilibrium is solved, allowing for more oil to be expulsed as the new curve will always be higher than the initial curve.

Gas Injection EOR Mechanism

The mechanisms of the gas injection EOR technique in unconventional liquid reservoirs are multi-contact miscibility, diffusion, oil swelling, and vaporization-condensation drive gas. The multi-contact miscibility takes place when the gas is in contact with the oil at a pressure above the MMP. Lighter and intermediate components of the oil are vaporized into the gas phase, which is also accompanied by the dissolution of gas molecules into the oil. As the gas keeps dissolving into the oil, oil swelling occurs which results in the production of the oil when the pore space is not adequate to contain the oil anymore. During the production period, the vaporized oil is carried by the gas and then condenses to the liquid phase at room conditions.

The other mechanism of gas injection EOR is diffusion. The driving mechanism of the diffusion process is the concentration difference based on Fick's law. At the beginning of the gas injection process, a significant concentration gradient exists between the gas and the oil phases. Diffusion process occurs on the interface between gas and oil, which results in oil recovery in shale reservoirs. However, the primary mechanism of gas injection EOR is multi-contact miscibility, which has been demonstrated in our previous publication (Zhang et al. 2019a).

Core-Scale Modeling

In this study, upscaling is achieved by conducting history-match process on the core-scale experiments which are previously executed in the laboratory. PVT properties, diffusion coefficient, capillary pressure, and relative permeability are modified to match the oil production given by the core-scale numerical model to the observed oil production on the laboratory-scale study. Then, the set of properties that result in the best match is applied to the field-scale model to provide an insight into the efficacy of this process on the well-per-well basis. This section contains the steps included in constructing the core-scale model.

Heterogeneity is a well-known major issue when dealing with shale rock samples. Since the quality of the field-scale result is strongly dependent on the accuracy of the core-scale model, heterogeneity is a crucial aspect to be included in the core-scale grid model. Computed Tomography (CT) technology is incorporated in constructing the core plug grid model. By scanning each of the core plugs used in the study through a medical CT-Scan, the density distribution of each core plug in a 3D plane is collected. The density distribution is converted into porosity distribution, allowing for the inclusion of heterogeneity into the core plug grid model. Original oil in place (OOIP) of each plug from both the actual core and the core model are also compared. Any discrepancy between the two values will be reconditioned before proceeding into the gas and SASI modeling.

Core-scale SASI modeling is developed by a history-match of oil recovery from the imbibition experiments. Capillary pressure and relative permeability are two properties to be modified in order to match the oil production. The modeling is also done on the grid model constructed from the CT-Scan images. Initial and final capillary pressure is derived from scaling group analysis. Measured laboratory data (contact angle, IFT, and spontaneous imbibition experiment data) are applied to our defined scaling group to estimate the capillary pressure during the imbibition process (Zhang et al. 2018c). The adsorption isotherm of the surfactant used is retrieved from previous studies using the same surfactant on the same reservoir rock (Alhashim et al. 2019; Alvarez et al. 2018). Initial and final relative permeability curves are constructed by trial-and-error of implementing multiple sets of curves on the core-scale numerical model. The curves which give the best match to the oil production observed from the laboratory-scale experiment are picked. At the end of the core-scale SASI modeling part, a set of two capillary pressure curves, a set of two relative permeability curves, and surfactant adsorption isotherms are obtained to be used for the field-scale modeling.

Core-scale gas injection model is constructed using CT-scan image to represent the heterogeneity of core plugs. The diffusion coefficient is the only parameter that can be adjusted in the simulator to show the effect of gas injection EOR. An accurate PVT table is essential to achieve the best match diffusion coefficient. A slim tube model and combined with Gas Chromatography (GC) results to history match the MMP experimental data were developed. The validated PVT table is then implemented to the core-scale model to history match gas injection experimental data. The best history match diffusion coefficient is applied to the field-scale model to evaluate the oil production enhancement using gas injection technique.

Field-Scale Modeling

The full-scale reservoir simulation model is constructed combining hydraulic fracturing simulation results, laboratory measurement, and scaling parameters achieved from core-scale history match. A mixed gridding structure is utilized to decrease the simulation time and ensure the accuracy of simulation results. The grids surrounding and inside the hydraulic fractures are constructed of homogeneous 2 ft long, wide, and thick grids. A logarithmic gridding structure is applied to the grids far away from the hydraulic fractures. The size ratio between every two adjacent grids is less than 1.5, which decreases the simulation error caused by gridding algorithm and speeds up the simulation time. The field-scale model is a single well dual-porosity model, which is validated by history match of an actual well production data. Different EOR field applications are investigated using the field-scale model to predict the performance of these techniques in unconventional liquid reservoirs.

The field-scale model contains two adjacent hydraulic fracture stages, with five clusters for each stage. The dimensions of this reservoir model are 600 ft (length) by 1,600 ft (width) by 120 ft (height) with 500 ft half-length hydraulic fractures. The diffusion coefficient, capillary pressure curve, and relative permeability curve are implemented into the field scale model to test the effectiveness of SASI EOR, gas injection EOR, and Hybrid EOR applications. The other parameters (such as permeability and porosity of matrix and natural fractures, water saturation, etc.) are determined from history match the actual well production data.

Results and Discussion

Gas injection EOR, SASI EOR, and Hybrid EOR techniques were investigated through laboratory experiments to evaluate their potential in unconventional liquid reservoirs. Contact angle, IFT, surfactant adsorption, spontaneous imbibition, and gas Huff-n-Puff experiments were performed to gather enough data for numerical simulation, and the experimental results are presented in the first section. Core-scale SASI and gas injection simulation models were constructed to history match the experimental data. Capillary pressure curves, relative permeability curves, and diffusion coefficient are determined from a history match process. These parameters are implemented in the reservoir model to evaluate the performance of different EOR techniques in shale reservoirs. Finally, the field-scale model is developed and validated by history matching the actual production data. Various EOR field applications are investigated using the field-scale model.

Laboratory Experimental Results

The gas injection experiments were performed using saturated side-wall shale core plugs at different injection pressures. Five gas injection experiments were mounted inside of a CT-scanner and operated at reservoir temperature. Produced oil from each Huff-n-Puff cycle was recorded until zero oil is observed at the outlet of the core holder, and the ultimate oil recovery was calculated based on the original oil in place. Injection pressure for gas injection experiments was determined from the MMP. The experimental pressures varied from 1,400 psi to 3,500 psi, in which two pressure below the MMP and the other beyond the MMP.

The MMP of CO_2-oil system was measured using the slim tube method, which is the most accurate method to determine the MMP. In order to understand the mechanism of gas injection EOR better, we designed the gas injection experiments in consideration of the MMP. In this study, the MMP of CO_2-Eagle Ford oil system was determined to 2,132 psi.

Five experimental pressures were tested through gas injection experiments. Two pressures were below the MMP (1,400 psi and 1,800 psi) and three above the MMP (2,500 psi, 3,000, and 3,500 psi). The ultimate oil recovery for all five gas injection experiments and recovery factors as a function of time for the maximum oil recovery case are presented in Fig. 1. The maximum ultimate oil recovery from gas injection experiments is 50% OOIP, which was achieved from the experimental pressure at 3,500 psi. Around half of the total oil produced was recovered during the first Huff-n-Puff cycle with less and less oil produced at the subsequent cycles. This observation not only demonstrates the great potential of the gas injection process to improve oil but also presents the efficiency of gas injection EOR recovery in shale reservoirs as most of the total oil recovered is produced during the first cycle.

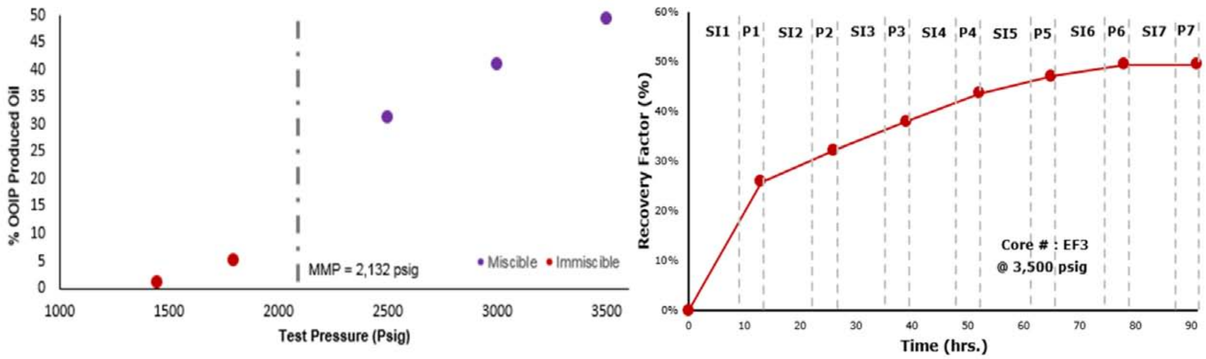

Figure 1—Ultimate recovery factors for gas injection experiments at different pressures (left) and recovery factor as a function of time for the 3,500 psi case.

Increasing the injection pressure was observed to always lead to additional oil recovery. This trend was observed to be stronger when the experimental pressure is above the MMP. The ultimate oil recovery at the end of the last cycle was 50% of the OOIP at injection pressure above the MMP. However, when the injection pressure was set below the MMP, the recovery factor decreased to less than 5% of the OOIP. Since the primary mechanism of gas injection EOR is the multi-contact miscibility, the oil production enhancement effect can only be triggered when the injection pressure beyond the MMP.

In order to evaluate the possibility of combining gas injection and SASI methods, SASI experiment was executed on the exact same core plugs that were previously utilized on the gas injection experiment. Surfactant selection for the SASI experiment was performed by investigating the degree of alteration on IFT and wettability. In addition, surfactant adsorption isotherm was also measured as it is needed to construct a numerical model of the SASI process. For simplicity, only one surfactant was used on all the five core plugs. The contact angle, IFT, and adsorption isotherm data of this surfactant are presented in Fig. 2. A significant wettability alteration was observed when the surfactant is added into the oil/water/rock system. The initially oil-wet rock was modified by the surfactant molecule to be water-wet with the contact angle decreasing from 108° to 50°. Interfacial tension of oil and water also decreased under surfactant influence, dropping the value from 31.43mN/m initially to 6mN/m. On the right figure of Fig. 2, surfactant adsorption isotherm is also presented, which will serve as an important input on the SASI numerical simulation. The amount of surfactant adsorbed on each concentration serves as the weighting factor in the interpolation between the initial and surfactant capillary pressure and relative permeability curves.

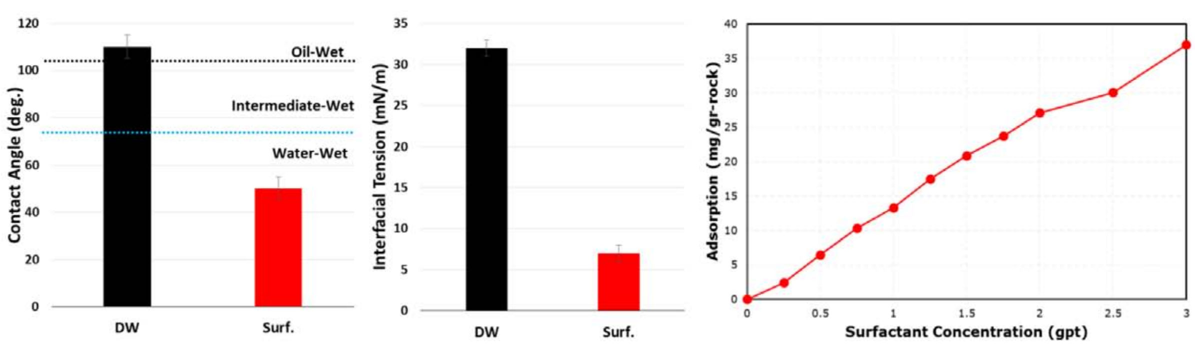

Figure 2—Results of contact angle (left), IFT (middle), and surfactant adsorption measurements (right).

The ultimate evaluation of the surfactant efficacy was done through the spontaneous imbibition experiment. Each of the five core plugs from the gas injection experiment was submerged for 10 days in 2gpt of the surfactant solution in a modified Amott cell under reservoir temperature. The results of the spontaneous imbibition experiments are presented in Fig. 3. It was observed that although the gas injection experiment already recovered a substantial amount of oil from the core sample, additional oil recovery was still observed from the SASI experiment. The addition of proper surfactant into the system after gas injection could lead to up to an additional 11.5% OOIP from this laboratory experiment. It was also observed that the core plug that had already produced 50% OOIP from the gas injection experiment was still able to produce an additional 8% OOIP when the sample is submerged in surfactant solution. These experimental results provide evidence that the combination of gas injection and SASI EOR techniques are a feasible method to achieve optimum oil recovery in unconventional liquid reservoirs.

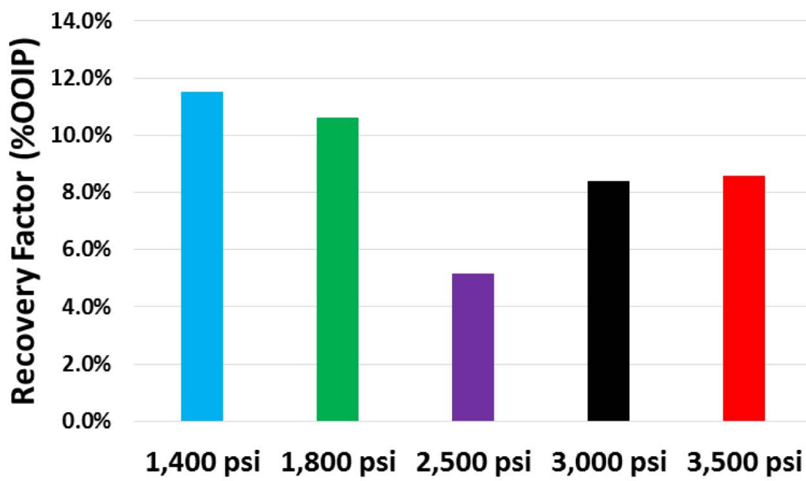

Figure 3—Results of Spontaneous imbibition experiments.

Core-Scale Modeling

In order to reveal the mechanisms of both gas injection EOR and SASI EOR, a numerical model of the laboratory-scale experiments are constructed. CT-Scan of each of the five core plugs used is converted into a porosity distribution and constructed as grids for the numerical simulator. History-match of both gas injection and spontaneous imbibition are executed on this core-scale numerical model. History-match for the spontaneous imbibition is achieved by modifying the capillary pressure and relative permeability. While for the gas injection, the diffusion coefficient is chosen as the variable to be changed to match the laboratory data. This information will then be used on the field-scale numerical model to provide an insight into the efficacy of the hybrid gas and surfactant EOR method on the well-per-well basis. A validated PVT table is generated by taking into account the GC measurement results and the history-match MMP data. Then, the diffusion coefficient is determined from the history matching gas injection experimental data. Finally, the capillary pressure and relative permeability curves are estimated from scaling group analysis and a history match of the laboratory spontaneous imbibition experiments.

A 1D slim tube model is developed based on the dimensions of the coil tube and its properties (such as porosity, pore volume, etc.). Oil composition and an initial PVT table are achieved from GC results, and injection pressures and rates are consistent with the experimental ones. The MMP data is history matched by adjusting the K-value table, and the best history match results are presented in Fig. 4. The validated PVT table for the Eagle Ford oil used in this study is then applied to core-scale simulation.

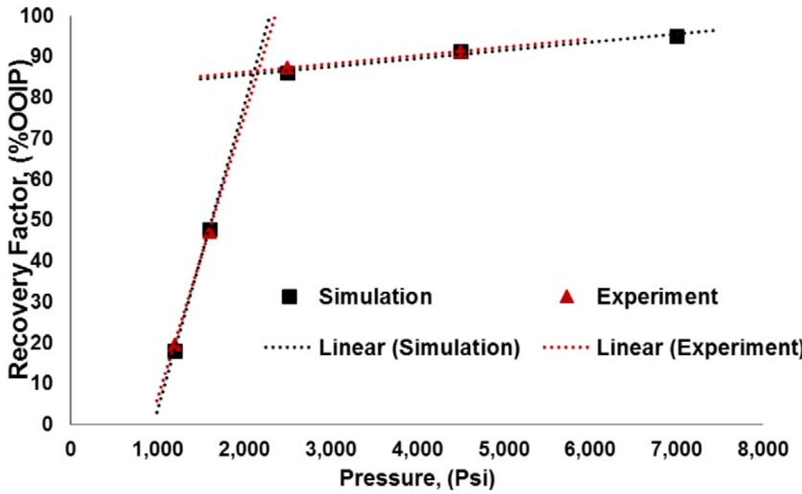

Figure 4—Result of history match MMP data.

Core-scale models for all core plugs utilized in the gas injection and the imbibition experiments are constructed from CT images. This method of model construction is beneficial as it allows for the incorporation of the shale core sample heterogeneity. Two core plugs used on the gas injection experiments at 1,400 psi and 3,000 psi are presented in Fig. 5 as an example to illustrate our core-scale model. It can be seen that by constructing the core-scale numerical model from CT images, the heterogeneity of the actual rock is transferred into the model, allowing for a more accurate representation of the model. In addition, an accurate core-scale model is highly essential when used as an upscaling method.

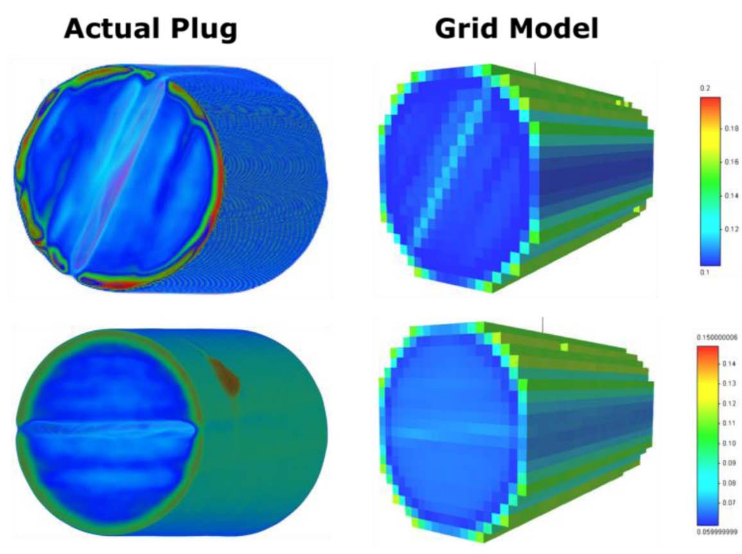

Figure 5—Comparison of the CT-scan image (left) and core-scale models (right).

After obtaining the validated PVT, history-match of the gas injection laboratory experiments is performed on the core-scale model previously mentioned. Diffusion coefficient is the primary parameter to be tuned to match the experimental data. The best history match results of each gas injection experiment are presented in Fig. 6. History match results have a decent agreement with the gas injection experimental data. The corresponding diffusion coefficient at each pressure is also validated by the history match results shown in Fig. 7.

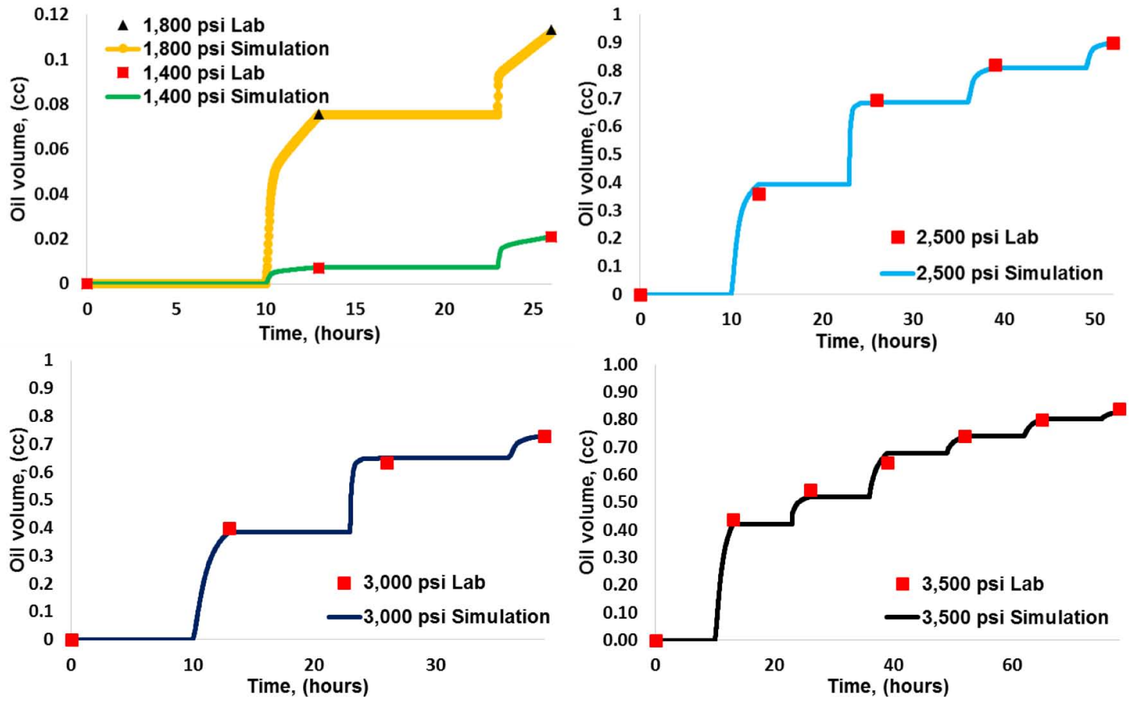

Figure 6—The history-matching results of gas injection experiments at different pressures.

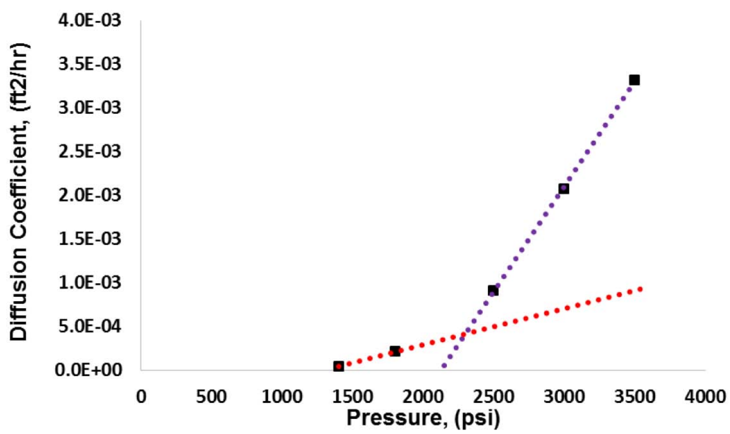

Figure 7—Diffusion coefficient of CO_2 achieved from gas injection history match results.

Typically, the diffusion coefficient possesses a positive linear correlation with pressure, which diffusion coefficient fits in a straight line. However, the diffusion coefficient achieved from the history match results fails to obey the correlation due to the history match diffusion coefficient combined the effect of multi-contact miscibility. The actual oil production enhancement effect of diffusion is along the red trend line, which plays a minor role in gas injection EOR. Multi-contact miscibility contributes the majority of oil recovery in gas injection experiments, which is indicated as the difference between the purple and the red trend lines.

For the next part, the history-match of the SASI laboratory experiment is performed. From this step, the relative permeability curves of both the base case and the surfactant case are gathered. Capillary pressure of both cases are retrieved from the scaling group analysis of the same imbibition laboratory experiment data beforehand (Zhang et al. 2018c). The history match process of SASI experiment is executed on the same core plug numerical model that is shown on the gas injection process before. With the only difference being the surrounding phase being the aqueous-phase for the SASI case. Initially, all grids constructing the rock have the capillary pressure and relative permeability of the base case. Once the surfactant is available inside of each grid, the adsorption function is triggered based on the adsorption isotherm previously provided. Then, based on the amount of surfactant adsorbed on each grid, new capillary pressure and relative permeability curves are calculated by interpolating the base curve and the surfactant curves with the amount of surfactant adsorbed as the weighting value. This algorithm allows for the surfactant-induced dynamic of the capillary and relative permeability to be included in the model.

Results from the SASI history match are presented in Fig. 8. Capillary pressure of both base and surfactant cases are presented on the left figure and the relative permeability of both cases on the right. An increment of the capillary pressure curve is observed when surfactant is available in the system. This increase in capillary pressure is expected as the alteration of wettability allows for more oil to be expulsed from the pore space by the capillary force alone. In addition, the intersection of capillary pressure and the x-axis is also shifted far to the right, allowing for capillary pressure to be sufficient at a broader range of saturation. On the relative permeability curves, it can be noticed that the oil relative permeability of the surfactant case is significantly higher than the base case while the opposite is displayed on the water curve. This phenomenon could be caused by the degree of wettability alteration caused by the surfactant to be larger compared to the extent of IFT reduction. As the rock surface is altered to be more water-wet by the surfactant molecule, the flow of water across the rock is hindered which is reflected by the lower relative permeability. On the contrary, oil flow under this altered wettability condition would be enhanced. Although that the reduction of IFT is well-known to increase the relative permeability of both oleic- and aqueous-phase, the minimum reduction caused by this particular surfactant could cause this effect to be minuscule compared to the effect of wettability alteration.

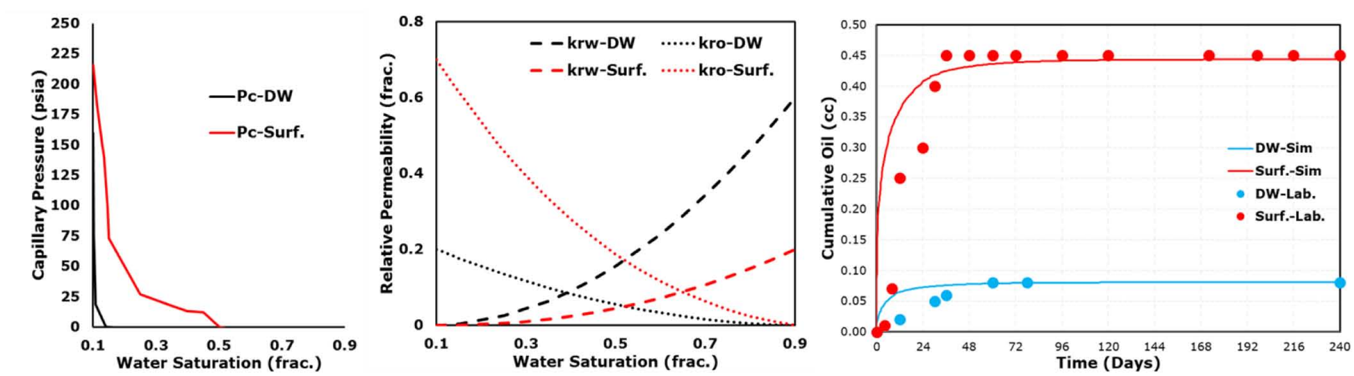

Figure 8—Capillary pressure curves from scaling group analysis (left), corresponding relative permeability curves (middle), and best history match results (right).

Diffusion coefficient, capillary pressure curves, and relative permeability were all achieved from the core-scale history. All these parameters are going to be implemented into the field-scale model to evaluate the effectiveness of different EOR applications in unconventional liquid reservoirs.

Field-Scale Modeling

In this study, the field-scale model is developed by combining the results from hydraulic fracturing simulation, laboratory experiments, and core-scale history match. In addition, to ensure the validity of the model, an actual well production data is history-matched before any EOR simulation case is executed. This step is important as in spite of the abundance of data from the core-scale modeling step, several important field-scale parameters (such as porosity, permeability, water saturation, natural fracture spacing, etc.) are still not available.

Two adjacent hydraulic fracture stages with 10 clusters are included in the reservoir model. The half-length of hydraulic fractures is 500 ft, and the fracture spacing is 50 ft. The geometries of the hydraulic fractures are constructed considering the stress shadow effect. Each fracture stage includes two well grown hydraulic fractures and three suppressed fractures to mimic what is often found in the field. The total dimensions of the reservoir model are 600 ft long, 1,600 ft wide, and 100 ft thick with a mixed gridding structure as presented in Fig. 9. Due to a large volume of natural fractures existing in shale reservoirs, the single well field-scale model is developed on a dual-porosity model.

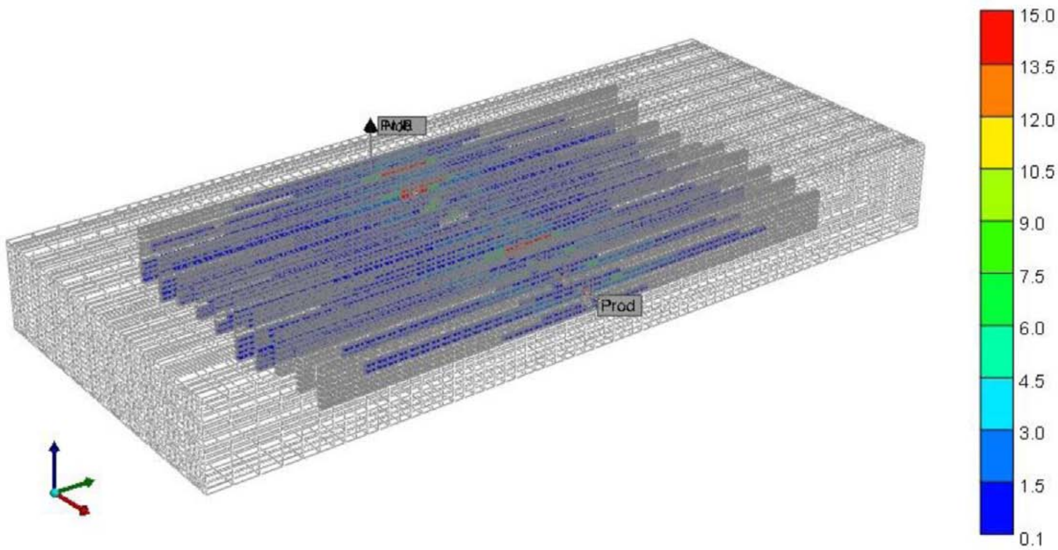

Figure 9—Gridding structure and permeability distribution in hydraulic fractures of the field-scale.

As mentioned previously, there are some reservoir properties that are still missing in order to construct a complete reservoir numerical model. Porosity, permeability, water saturation, and natural spacing are some examples of these properties. History match of an actual well production data is performed to fill the missing values. CMG CMOST is utilized to accelerate this process, and the best result is shown in Fig. 10. Both simulation and actual production data are in good agreement with less than 1% overall error. With the field-scale model now ready to be utilized, the next step of this study is to test different EOR scenarios with the involvement of SASI, gas, or both on the model. Four scenarios are assessed in this study which includes SASI in the completion followed by gas injection after primary depletion; gas injection following SASI after primary depletion; SASI following gas injection after primary depletion; and multi-cycle gas injection and SASI after primary depletion.

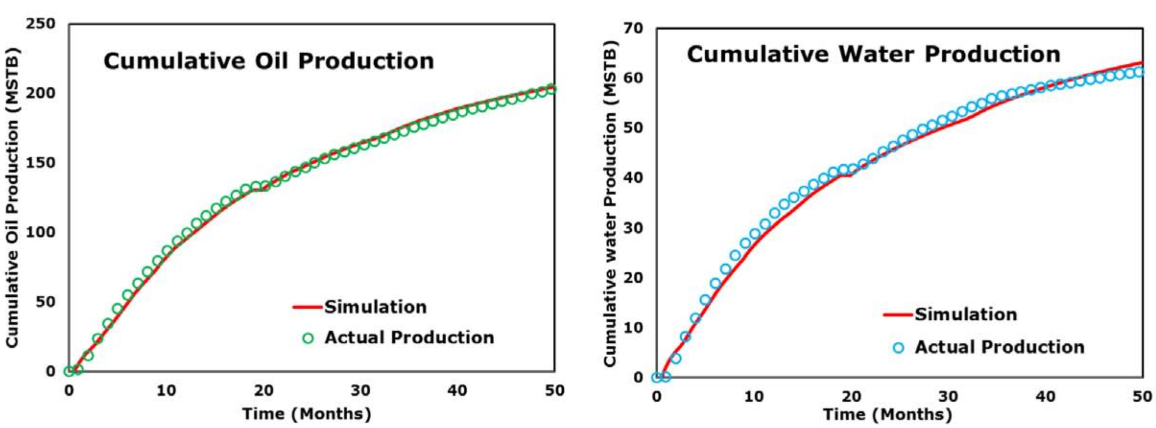

Figure 10—The history match results of the field-scale model to the actual oil (left) and water (right) production data.

Standard SASI EOR and Gas Injection EOR Field Application

In order to provide a comprehensive comparison of the effectiveness of the Hybrid EOR techniques, the standard application of SASI and gas injection on the field-scale must be investigated first. Three cases of standard surfactant and gas applications in ULR are presented, including, application of SASI in completion without any process after primary depletion, SASI after primary depletion, and gas injection after primary depletion. It is important to note that on the last two cases, the surfactant is not included in the completion phase of the well. The same is applied to the rest of the EOR cases in this manuscript. For any process applied after the primary depletion, the injection process is also designed to be starting after three years of oil production.

Integration of SASI into the completion process of a well is commonly believed as one method of applying surfactant EOR in the unconventional liquid reservoirs. The addition of a proper surfactant into the completion fluid results in a significant oil production enhancement from wettability alteration and IFT reduction. In this study, different surfactant concentrations are investigated to observe the effect of surfactant concentration on well performance. Capillary pressure and relative permeability curves used in all SASI EOR related simulation studies were constructed on the previous step of the work through scaling group and core-scale history match analysis of imbibition experimental data. The simulation results of cumulative oil production and oil recovery incremental for three surfactant concentrations (1, 2, and 4 gpt) are presented in Fig. 11. The oil recovery incremental is calculated by comparing the cumulative oil production to that of the base case, where no surfactant is present in the system. The addition of surfactant into the completion fluid leads to 4% oil production improvement compared to the base case. Oil recovery incremental increases as surfactant concentration increases, which is consistent with our previous studies. However, the surfactant concentration does not seem to show a strong production enhancement effect on this particular well.

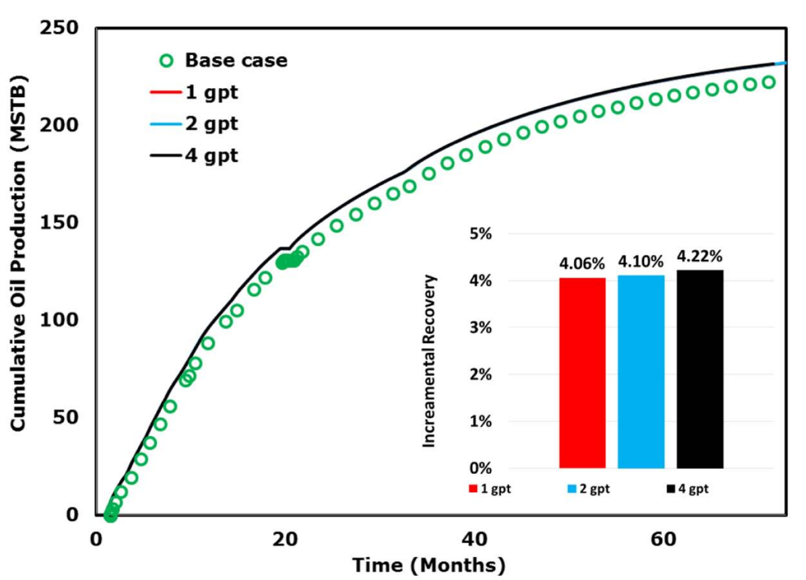

Figure 11—The results of cumulative oil production and recovery incremental for different surfactant concentrations in the completion fluid.

The second SASI EOR field application is the SASI injection EOR after primary depletion. In this simulation case, the surfactant is added into the well after the well has gone through three years of primary depletion. Surfactant addition should be able to provide additional oil recovery as it provides both pressure maintenance as well as oil/water/rock system alteration that could lead to better production through imbibition. The effect of both pressure and surfactant are investigated in this study by setting the numerical model under different injection pressures and surfactant concentrations. In general, the simulation results show that this EOR method is able to provide incremental recovery from the well, which is shown in Fig. 12.

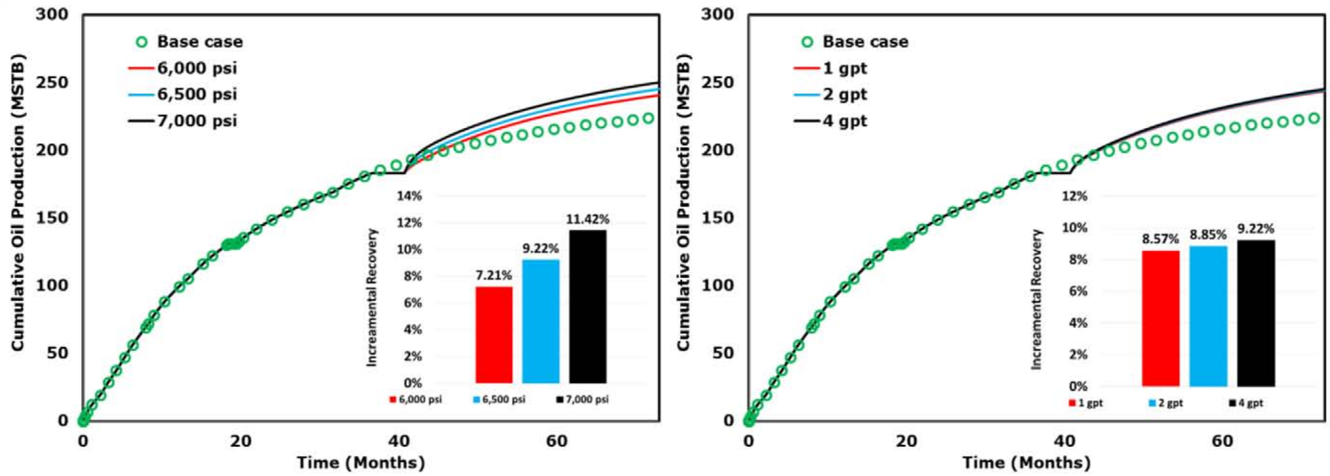

Figure 12—The results of cumulative oil production and recovery incremental for different injection pressures and surfactant concentrations in SASI injection process.

Three different injection pressures, 6,000 psi, 6,500 psi, and 7,000 psi, under constant surfactant loading of 2gpt are investigated to reveal the effect of injection pressure on this method. A positive correlation is observed between the final six-year cumulative recovery and the injection pressure. This result is expected as higher injection pressure directly re-energizes the reservoir better, leading to higher oil production after the injection period. In addition, higher injection pressure also correlates to a higher amount of surfactant solution injected into the reservoir, allowing for an even better production enhancement by the surfactant molecule. However, further increasing the injection pressure could result in a significant operation cost, especially when the injection pressure above 7,000 psi. From the simulation results of surfactant concentration study on 1, 2, and 4 gpt surfactant loading under constant 6500 psia injection pressure, we can observe that the higher the surfactant concentration leads to higher oil recovery. Similar to SASI EOR in the completion process, surfactant concentration fails to present a significant effect on improving oil recovery for this well. It is also important to note that the surfactant still needs to be present in the system for this method to succeed as injecting water without surfactant was determined to be less beneficial (Zhang et al. 2019b).

The third standard unconventional EOR application is the gas injection process after primary depletion. CO_2 is a promising EOR agent that has presented a significant oil production enhancement effect on both laboratory investigations and field applications. Two injection pressures are investigated on the field-scale model with the diffusion coefficient obtained from the core-scale simulation part of this study. The simulation results of cumulative oil production and recovery incremental for gas injection processes at 4,000 psi and 4,500 psi are presented in Fig. 13. The injection pressure shows a positive trend with oil recovery improvement. Up to 9% of oil recovery enhancement is achieved from gas injection at 4,500 psi. Higher injection pressure results in a larger quantity of oil reaching the miscible state, while simultaneously increases the reservoir pressure to a higher level. Increasing the injection pressure always leads to a higher cumulative oil production, which is consistent with the laboratory observations and follows the mechanisms of gas injection EOR.

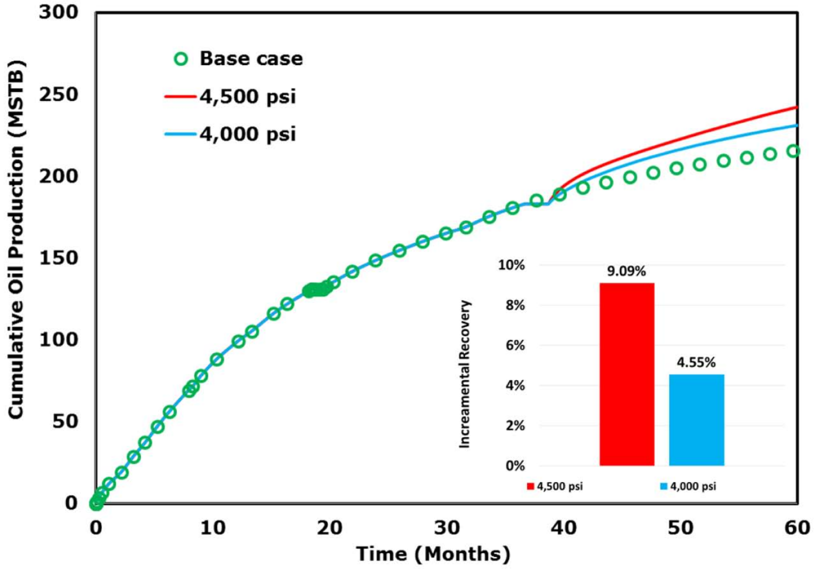

Figure 13—The results of cumulative oil production and recovery incremental for different injection pressures.

SASI EOR in the completion Followed by Gas Injection EOR Field Application

Previously, results from the standard application of unconventional EOR methods were presented. In the following section of this work, the simulation results of four different combined/hybrid EOR methods are discussed. The first scenario is the combination of SASI in the completion and gas injection after primary depletion, which will be referred to as Hybrid EOR 1. In the Hybrid EOR 1 scenario, 1gpt of surfactant loading is added into the completion fluid, primary depletion is allowed for three years, then gas injection under the injection pressure of 4,500 psi is performed. This combination might be the most well-suited scenario for most of the produced wells since surfactant was most-likely already added when the well was completed and gas injection EOR is the only method left to be applied on the already declining well. Cumulative oil production resulting from the implementation of this scenario on the field-scale model is presented in Fig. 14.

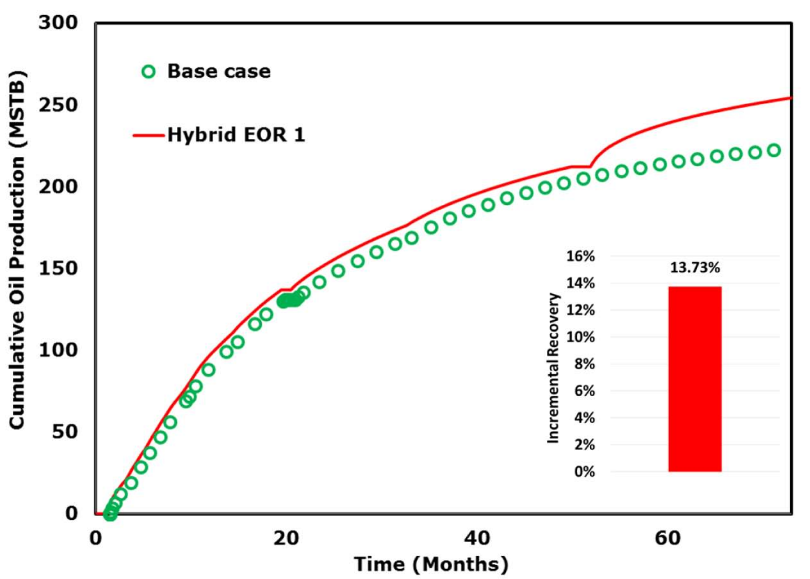

Figure 14—The results of cumulative oil production and recovery incremental for Hybrid EOR 1.

In comparison to the base case, the implementation of Hybrid EOR 1 is observed to produce an additional 13.7% of oil recovery. By comparing the recovery from this method to the three previous standard unconventional EOR methods, it can be seen that the combination of SASI and gas injection provides a better incremental recovery than any of the standard methods. It can also be seen that the incremental recovery form Hybrid EOR 1 is similar to the combined incremental recovery from SASI in completion and gas injection when performed separately. This could enforce the theory that SASI and gas injection recovers from two different spectrum of the hydrocarbon in place, which is also witnessed in the laboratory experiment. Future investigation is still needed to prove the theory. Nevertheless, Hybrid EOR 1 has shown its prospect in enhancing the oil recovery.

Gas Injection Following SASI Injection EOR Field Application

SASI injection after primary depletion which is then followed by gas injection is assessed next and will be referred to as Hybrid EOR 2. In this scenario, the surfactant is not a part of the completion fluid when the well is completed. After three years of primary depletion, the surfactant is injected into the reservoir under surfactant loading of 1gpt and an injection pressure of 7,000 psi for six months. Then, the injection of the surfactant solution is stopped, and gas injection at a pressure of 4,500 psi is performed. This scenario is well-suited to those wells that were not completed with surfactants and already passed through their primary depletion interval. The usual EOR mechanism of this type of wells is through the implementation of gas injection. However, Hybrid EOR 2 should also be considered as well since a significant oil recovery is observed from the field-scale model, which is shown in Fig. 15.

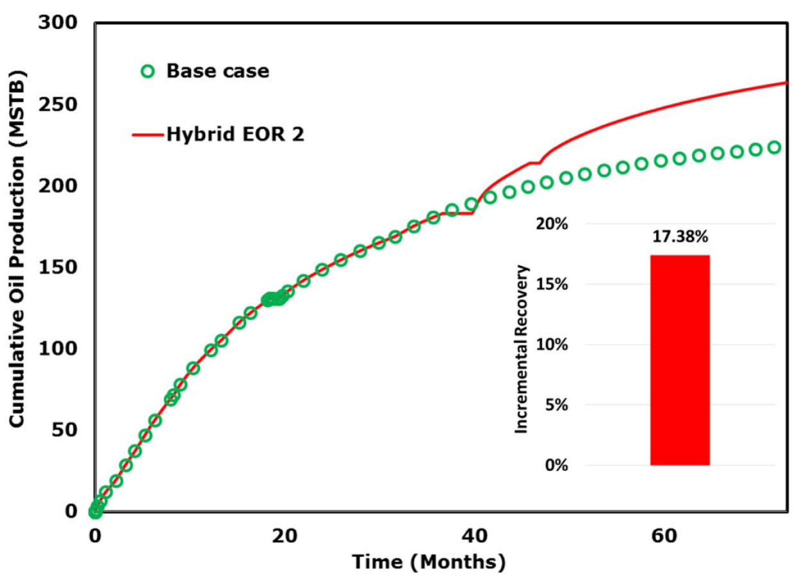

Figure 15—The results of cumulative oil production and recovery incremental for Hybrid EOR 2.

Hybrid EOR 2 is observed to produce the highest incremental recovery when compared to the Hybrid EOR 1 and the other three standard unconventional EOR applications with 17.4% incremental recovery achieved. Similar to the result of Hybrid EOR 1, incremental recovery from this scenario is also very close to the combination of incremental recovery from SASI after primary depletion and gas injection after primary depletion when performed separately. This observation enforces once again that the two methods recover from two different spectra of the hydrocarbon. It is also important to note that the comparison in this study is formulated by normalizing the recovery at the end of the six years period. From the figure above, it can be seen that the cumulative oil production from Hybrid EOR 2 still possesses a significant oil production capability at the end of year six. By increasing the simulation time step into more than six years, an even more significant incremental oil recovery would be achieved from the implementation Hybrid EOR 2.

SASI Injection Following Gas Injection EOR Field Application

The third scenario of the combined EOR technique field application is gas injection EOR which then will be followed by SASI injection EOR, denoted as Hybrid EOR 3. The simulation results of Hybrid EOR 2 provides the evidence that the combined injection EOR technique possesses the ability to increase oil production in unconventional reservoirs. In this section, we investigated the effect of the injection sequence on oil production enhancement. Similar to Hybrid EOR 2 study, the injection process starts after three-year oil production. Gas injection at 4,500 psi injection pressure is first applied to the well for six months; then surfactant is injected to the reservoir at 7,000 psi. The oil production and recovery incremental using Hybrid EOR 3 scheme are presented in Fig. 16.

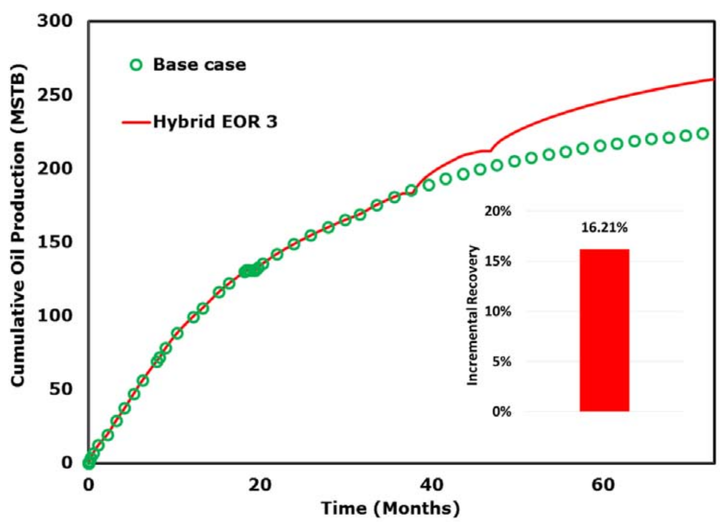

Figure 16—The results of cumulative oil production and recovery incremental for Hybrid EOR 3.

Hybrid EOR 3 scenario also presents a significant oil production enhancement. However, when compared to the results of Hybrid EOR 2, the oil recovery from Hybrid EOR 3 design is observed to be less than Hybrid EOR 2. Both Hybrid EOR 2 and 3 are performed under similar injection pressures for both SASI and gas injection with the only difference being the sequence of the process. As mentioned before, surfactant forms a stable layer on the rock surface to alter the wettability and decrease the IFT. Earlier injected surfactant into the reservoir results in more oil incremental. Based on the results, the SASI injection process applied earlier than gas injection could potentially increase oil recovery from the unconventional liquid reservoirs.

Multi-Cycle Gas and SASI Injection EOR Field Application

On the last tested scenario, multi-cycle gas injection and SASI injection is tested. It is important to note that all previously investigated scenarios only consist of a single cycle of injection of either gas or SASI. Two cases are investigated in this scenario, three cycles of gas injection after primary depletion and three cycles of SASI injection after primary depletion. The injection pressure of 4,500 psi is chosen for the gas case. On the SASI case, surfactant loading of 1gpt under injection pressure of 7,000 psi is performed.

Multi-cycle SASI injection scenario is designed with three cycles and surfactant concentration of 1 gpt. The cumulative oil production and recovery incremental are plotted in Fig. 17. From the results of the standard SASI injection study, the oil incremental for one cycle of SASI injection is up to 11%. Increasing the number of the cycle on SASI injection fails to provide significant improvement in oil production, especially when the number of injection cycle is larger than 2. The water-cut of Eagle Ford wells is typically very low.

The water saturation of hydraulic fractures increases as water is injected into the reservoir, which leads to oil relative permeability decrease. Increasing SASI injection cycles can significantly increase total liquid production, but oil production is suppressed as water saturation increases. In our previous study, multi-cycle SASI injection was observed to significantly improve oil recovery and extend well life for the high water-cut reservoir. Therefore, multi-SASI injection shows great potential to increase ultimate oil recovery for the reservoir with high water saturation, but may not be the best option for low water-cut reservoirs.

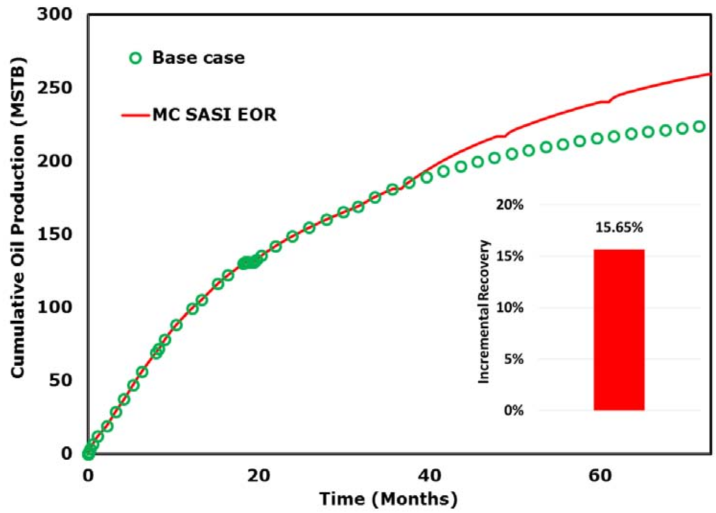

Figure 17—The results of cumulative oil production and recovery incremental for multi-cycle SASI injection EOR application.

Finally, the efficacy of multi-cycle gas injection on depleted shale oil wells is investigated. Injection pressure and injection time are kept as constants for each gas injection. Simulation result in the form of cumulative oil production and incremental oil recovery are presented in Fig. 18. The multi-cycle gas injection EOR (MC-Gas Injection EOR) technique presents the highest six-year cumulative oil production. Incremental oil recovery from multi-cycle gas injection increases to 24%. Cyclic-gas injection possesses a significant potential of increasing oil recovery in shale reservoirs, especially when the water saturation of the reservoir is low.

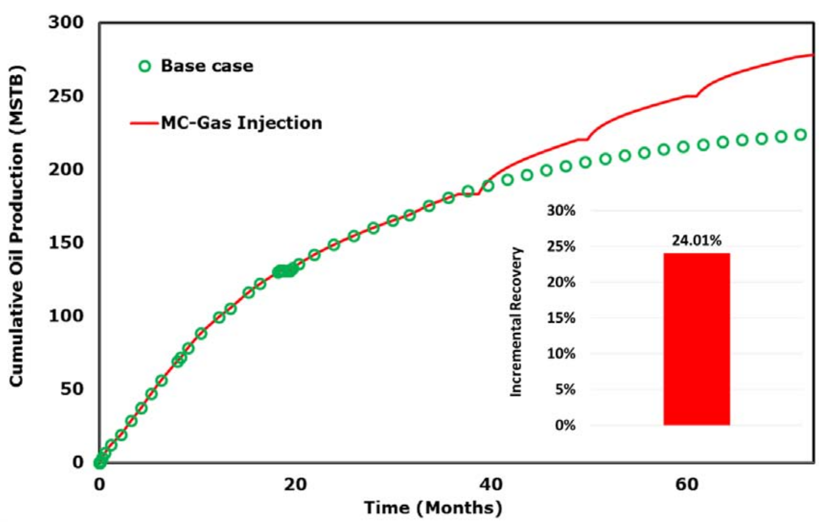

Figure 18—The results of cumulative oil production and recovery incremental for MC-Gas injection EOR application.

Conclusion

Based on the observations of laboratory experiments and numerical simulation results for a specific Eagle Ford well EOR applications, we conclude:

1. Gas injection EOR in unconventional liquid reservoirs through hydraulic fractures results in higher oil production. This gas EOR effect is observed in the laboratory experiments and numerical simulation results.
2. Surfactant as an EOR agent shows significant potential in increasing oil recovery in unconventional liquid reservoirs from laboratory experiments and numerical simulation with both applications as a part of the completion fluid or as an EOR agent after the primary depletion.
3. Combined EOR techniques result in further oil production enhancement, which opens the possibility of achieving a better oil recovery from shale reservoirs.
4. In applying combined/hybrid EOR methods, sequencing is an essential part of the design. From this study, it was observed that performing SASI injection before gas injection could result in lower recovery than the scenario of gas injection performed first before SASI.
5. Multi-cycle gas injection EOR can archive the highest oil recovery compared to the other combined EOR scenarios for low water-cut well.

Acknowledgments

The authors would like to show their appreciation to the staff and student worker at the Petroleum Engineering Department at Texas A&M University for their collaboration on the laboratory work and data collection. The authors are thankful to Crisman Institute for Petroleum Research at Texas A&M University, Halliburton, Marathon Oil, Chevron, Pioneer Natural Resources for providing equipment or funding this project.

Nomenclature

k = Permeability
P_c = Capillary pressure
r = Radius of curvature
θ = Contact angle
σ = Interfacial tension (IFT)
ϕ = Porosity
CA = Contact angle
CT = Computed tomography
EOR = Enhanced oil recovery
GC = Gas Chromatography
OOIP = Original oil in place
PVT = Pressure-Volume-Temperature
SASI = Surfactant-Assisted Spontaneous Imbibition
ULR = Unconventional Liquid Reservoir

Reference

Adel, I.A., Tovar, F.D., and Schechter, D.S. 2016. Fast-Slim Tube: A Reliable and Rapid Technique for the Laboratory Determination of Mmp in CO2 - Light Crude Oil Systems. Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, USA. https://doi.org/10.2118/179673-ms.

Adel, I.A., Tovar, F.D., Zhang, F. et al 2018a. The Impact of Mmp on Recovery Factor During CO2 – EOR in Unconventional Liquid Reservoirs. Presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA. 17. https://doi.org/10.2118/191752-MS.

Adel, I.A., Zhang, F., Bhatnagar, N. et al 2018b. The Impact of Gas-Assisted Gravity Drainage on Operating Pressure in a Miscible CO2 Flood. Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, USA. https://doi.org/10.2118/190183-ms.

Afra, S., Nasr-El-Din, H.A., and Samouei, H. 2019. Characterization of Iron Interaction with Viscoelastic Surfactant (Ves)-Based Stimulation Fluid. Presented at the SPE Western Regional Meeting, San Jose, CA, USA. https://doi.org/10.2118/195373-ms.

Alhashim, H., W, Zhang, F., and Schechter, D.S. 2019. Investigation of the Effect of Pore Size Distribution on the Produced Oil from Surfactant-Assisted Spontaneous Imbibition in Ulr Using Nmr. Presented at the SPE Annual Technical Conference and Exhibition, Calgary, Albert, Canada. https://doi.org/10.2118/195931-MS

Alvarez, J.O., Saputra, I.W.R., and Schechter, D.S. 2017a. The Impact of Surfactant Imbibition and Adsorption for Improving Oil Recovery in the Wolfcamp and Eagle Ford Reservoirs. Presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA. https://doi.org/10.2118/187176-ms.

Alvarez, J.O., Saputra, I.W.R., and Schechter, D.S. 2017b. Potential of Improving Oil Recovery with Surfactant Additives to Completion Fluids for the Bakken.*Energy & Fuels* **31** (6): 5982–5994. https://doi.org/10.1021/acs.energyfuels.7b00573.

Alvarez, J.O., Saputra, I.W.R., and Schechter, D.S. 2018. The Impact of Surfactant Imbibition and Adsorption for Improving Oil Recovery in the Wolfcamp and Eagle Ford Reservoirs. *SPE Journal* **23** (06): 2103–2117. SPE-187176-PA. 10.2118/187176-PA.

Bao, A. and Gildin, E. 2017. Data-Driven Model Reduction Based on Sparsity-Promoting Methods for Multiphase Flow in Porous Media. Presented at the SPE Latin America and Caribbean Petroleum Engineering Conference, Buenos Aires, Argentina. 16. https://doi.org/10.2118/185514-MS.

Bao, A., Hazlett, R.D., and Babu, D.K. 2017. A Discrete, Arbitrarily Oriented 3d Plane-Source Analytical Solution to the Diffusivity Equation for Modeling Reservoir Fluid Flow. *SPE Journal* **22** (05): 1609–1623. SPE-185180-PA. https://doi.org/10.2118/185180-PA.

Deng, L. and King, M.J. 2018. Theoretical Investigation of the Transition from Spontaneous to Forced Imbibition. Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, USA. https://doi.org/10.2118/190309-ms.

Kou, R., Moridis, G.J., and Blasingame, T.A. 2018. Analysis and Modeling of Proppant Transport in Inclined Hydraulic Fractures. Presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA. https://doi.org/10.2118/189856-ms.

Pan, Y., Zhou, P., Deng, L. et al 2019. Production Analysis and Forecasting for Unconventional Reservoirs Using Laplacian Echo-State Networks. Presented at the SPE Western Regional Meeting, San Jose, California, USA. 28. https://doi.org/10.2118/195243-MS.

Saputra, I.W.R. and Schechter, D.S. 2018. Comprehensive Workflow for Lab to Field-Scale Numerical Simulation to Improve Oil Recovery in the Eagle Ford Shale by Selective Testing and Modeling of Surfactants for Wettability Alteration. Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Houston, Texas, USA. https://doi.org/10.15530/urtec-2018-2884598.

Tang, H., Killough, J.E., Heidari, Z. et al 2017. A New Technique to Characterize Fracture Density by Use of Neutron Porosity Logs Enhanced by Electrically Transported Contrast Agents. *SPE Journal* **22** (04): 1034–1045. SPE-181509-PA. https://doi.org/10.2118/181509-PA.

Tang, H., Yan, B., Chai, Z. et al 2018. Analyzing the Well-Interference Phenomenon in the Eagle Ford Shale/Austin Chalk Production System with a Comprehensive Compositional Reservoir Model. *SPE Reservoir Evaluation & Engineering Preprint* (Preprint): 15. SPE-191381-PA. https://doi.org/10.2118/191381-PA.

Tovar, F.D., Barrufet, M.A., and Schechter, D.S. 2018a. Gas Injection for EOR in Organic Rich Shale. Part I: Operational Philosophy. Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, USA. https://doi.org/10.2118/190323-ms.

Tovar, F.D., Barrufet, M.A., and Schechter, D.S. 2018b. Gas Injection for EOR in Organic Rich Shales. Part Ii: Mechanisms of Recovery. Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Houston, Texas, USA. 21. 10.15530/URTEC-2018-2903026.

Xue, X., Yang, C., Park, J. et al 2018. Reservoir and Fracture-Flow Characterization Using Novel Diagnostic Plots.*SPE Journal Preprint* (Preprint): 22. SPE-194017-PA. https://doi.org/10.2118/194017-PA.

Yang, C., Xue, X., King, M.J. et al 2017. Flow Simulation of Complex Fracture Systems with Unstructured Grids Using the Fast Marching Method. Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Austin, Texas, USA. 18. https://doi.org/10.15530/URTEC-2017-2691393.

Yang, D., Xue, X., and Chen, J. 2018. High Resolution Hydraulic Fracture Network Modeling Using Flexible Dual Porosity Dual Permeability Framework. Presented at the SPE Western Regional Meeting, Garden Grove, California, USA. 14. https://doi.org/10.2118/190096-MS.

Zhang, F., Adel, I.A., Park, K.H. et al 2018a. Enhanced Oil Recovery in Unconventional Liquid Reservoir Using a Combination of CO2 Huff-N-Puff and Surfactant-Assisted Spontaneous Imbibition. Presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA. 20. https://doi.org/10.2118/191502-MS

Zhang, F., Adel, I.A., Saputra, I.W.R. et al 2019a. Numerical Investigation to Understand the Mechanisms of CO2 EOR in Unconventional Liquid Reservoirs. Presented at the SPE Annual Technical Conference and Exhibition, Calgary, Albert, Canada. https://doi.org/10.2118/196019-MS

Zhang, F., Saputra, I.W.R., Adel, I.A. et al 2018b. Scaling for Wettability Alteration Induced by the Addition of Surfactants in Completion Fluids: Surfactant Selection for Optimum Performance. Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Houston, Texas, USA. 17. https://doi.org/10.15530/URTEC-2018-2889308.

Zhang, F., Saputra, I.W.R., Niu, G. et al 2018c. Upscaling Laboratory Result of Surfactant-Assisted Spontaneous Imbibition to the Field Scale through Scaling Group Analysis, Numerical Simulation, and Discrete Fracture Network Model. Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, USA. https://doi.org/10.2118/190155-ms.

Zhang, F., Saputra, I.W.R., Parsegov, S.G. et al 2019b. Experimental and Numerical Studies of EOR for the Wolfcamp Formation by Surfactant Enriched Completion Fluids and Multi-Cycle Surfactant Injection. Presented at the SPE Hydraulic Fracturing Technology Conference Woodlands, TX, USA. https://doi.org/10.2118/194325-ms.

Zhang, S. and Zhu, D. 2017. Inversion of Downhole Temperature Measurements in Multistage Fracture Stimulation in Horizontal Wells. Presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA. 19. https://doi.org/10.2118/187322-MS.

Zhang, S. and Zhu, D. 2019. Efficient Flow Rate Profiling for Multiphase Flow in Horizontal Wells Using Downhole Temperature Measurement. Presented at the International Petroleum Technology Conference, Beijing, China. 17. https://doi.org/10.2523/IPTC-19138-MS.

Zhu, D., Hill, D., and Zhang, S. 2018. Using Temperature Measurements from Production Logging/Downhole Sensors to Diagnose Multistage Fractured Well Flow Profile. Presented at the SPWLA 59th Annual Logging Symposium, London, UK. 13.

Zou, A. and Schechter, D. 2017. Investigation of the Oil Recovery Mechanism During Laboratory CO2 EOR Experiments with Unconventional Shale Cores through Compositional Simulation. Presented at the Carbon Management Technology Conference, Houston, Texas, USA. https://doi.org/10.7122/486243-ms.