

An Experimental and Numerical Study of Asphaltene-Induced Formation Damage during CO₂ Miscible Flooding

Fahad I. Syed^{1,2}, Shahin Neghabhan¹, Arsalan Zolfaghari¹, Amirmasoud K. Dahaghi¹

¹University of Kansas

²ADNOC Offshore

Corresponding Author: Fahad I. Syed

ABSTRACT: Asphaltene precipitation, flocculation, and deposition can significantly reduce oil production by impacting wellbores, flowlines, and more importantly, formations' pore space around the well. Any alteration in the temperature, pressure and fluid composition can trigger asphaltene deposition. The ability to predict the occurrence and magnitude of the asphaltene deposition is a major step for flow assurance. An accurate prediction of the deposition envelope enables the operator to systematically categorize different cases based on their impact on the production. This critical knowledge can be used to predict the occurrence and magnitude of asphaltene deposition, which could potentially save the expense of installing unnecessary equipment and injecting chemical inhibitors when they are not needed.¹⁻³

Predicting asphaltene-related flow assurance issues requires robust physically-based modeling capabilities for capturing the asphaltene's deposition tendencies as a function of the prevailing field's operating conditions. Although available simulators are found to be useful for predicting asphaltene's phase behavior, precipitation tendency, and instability curves, they often overlook important physical characteristics of the asphaltenes. These properties may have a detrimental role in obtaining a realistic representation of the asphaltene deposition behavior.

In this paper, the experimental and the numerical investigations are combined to present a comprehensive methodology for studying the thermodynamics of asphaltene precipitation and deposition. A wide range of pressures and CO₂ concentrations are covered that are relevant to actual CO₂ flooding in Middle East oil reservoir. To do so, a series of lab experiments including routine and special PVT analyses where the asphaltene onset points and saturation pressures were measured for different compositions of the reservoir oil and CO₂ mixtures. Furthermore, detailed recommendations are presented in this paper to tune an EOS for running compositional simulations when unstable asphaltene is reported based on the lab experimental measurements.

Keywords—Asphaltene, EOS Tuning, Asphaltic Fluid & CO₂ field problems

Date of Submission: 25-02-2020

Date of acceptance: 05-03-2020

I. INTRODUCTION

Asphaltenes are the polar, poly-aromatic and heaviest hydrocarbon fraction of crude oil that are soluble in light aromatic hydrocarbons and solvents such as benzene and toluene but insoluble in low molecular weight paraffin.⁴⁻⁷ As a result of reservoir fluid depressurization, asphaltene particles may precipitate followed by aggregation and deposition on the rock surfaces and plug pore throats causing formation damage (i.e., permeability reduction and wettability alteration). This is because asphaltene deposition could potentially alter the surface wettability towards more oil-wet conditions impacting oil relative permeability for the near-the-wellbore formation. The injection of different displacing fluid during Enhanced Oil Recovery (EOR) processes could change reservoir fluid composition resulting in the asphaltene flocculation and deposition.⁸⁻¹⁰ It is worth noting that a higher content of asphaltene in a reservoir fluid is not necessarily problematic unless it becomes thermodynamically unstable and starts precipitation and flocculation to form larger molecules that would easily deposit on the rock surface.

There are several factors that may lead to asphaltene precipitation and deposition. Along with the reservoir fluid properties and composition as well as the rock mineralogy and pore throat size distribution (PTSD), electro-kinetic effects due to streaming potential generation by means of reservoir fluid flow, asphaltene to resin ratio and the amount of formation brine and its composition, etc. are considered as the potential factors to contribute to formation damage due to asphaltene flocculation that easily proceed towards deposition.^{11,12}

The injectivity and productivity of wells are often altered due to the asphaltene deposition in the formation around the wellbore, within the wellbore, and pipelines and processing facilities used at the surface.^{13,14} As mentioned, the alteration of fluid composition near gas injection well or a pressure drawdown near a producer well could trigger asphaltene precipitation and deposition within the pore space of the formation near the wellbore.^{13,15,21}

Gas injection is considered as one of the desired secondary and/or tertiary recovery methods to minimize the residual oil saturation (Sor), increasing oil recoveries especially in light to medium quality oil reservoirs.^{13,21} Several researchers, however, concluded that the miscible and/or immiscible gas injection cause changes in the reservoir fluid composition and hence may result in asphaltene precipitation followed by formation damage. Formation damage due to asphaltene deposition may cause serious production losses because of the reduction in well productivity. Most operators adopt the remedial solutions after evidence of asphaltene precipitation (such as chemical treatment and workover operations) rather than its prevention due to late detection of this problem.¹⁴ The dynamic core-flooding experimental analysis is one of the most effective methods that could be utilized to determine the potential of asphaltene precipitation and deposition in the formation's pore space under reservoir conditions. However, it would never be the exact representation of the reservoir in a controlled and limited environment of a laboratory core scale but the closest lab conditions mimicking the reservoir flow and the thermodynamics will definitely give an idea of the possible asphaltene flow dynamics.¹

For the dynamic aspects of asphaltene precipitation and deposition in the reservoir, there are several experimental measurements that show the precipitation process, whether it is due to pressure depletion or gas injection, is largely reversible. However, there can be significant hysteresis in the re-dissolution process, i.e. the time required for the asphaltene to dissolve back may be considerably longer than the time required for the original precipitate to form especially after being flocculated.^{17,18}

It was observed that reservoirs with asphaltene precipitation issues usually have the following characteristics¹⁹:

- The in situ reservoir fluid is light to medium grade oil with small asphaltene content.
- The initial reservoir pressure is much higher than the bubble point pressure of the reservoir.
- Maximum precipitation occurs around the bubble point pressure.
- Heavier crudes have less asphaltene precipitation problems as they can dissolve more asphaltene.

Reservoir characterization is one of the most important steps in the modeling of asphaltene precipitation and deposition particularly during the splitting of heavier hydrocarbon components. Several different methods are discussed in the literature for the fluid characterization step. Here in this work, we adopt the guidelines of Darabi²⁰ and Khan¹⁹. We use a wide range of routine and special PVT experimental data (e.g., bubble point pressures and asphaltene onset pressures (AOP) for different concentration of CO₂ and reservoir oil) to tune the EOS. Asphaltene precipitation is a thermodynamic property of hydrocarbon fluid mixture. Hence, the AOP is a dynamic number that is sensitive to the system pressure, temperature and the overall fluid composition.^{1,21}

II. RESERVOIR FLUID CHARACTERIZATION

Before any compositional simulation, the most essential step is to characterize the reservoir fluid by validating against the corresponding laboratory measurements. In this work, the following set of guidelines are utilized for fluid characterizations to minimize the discrepancy between the simulation results and experimental counterparts. The key factors to keep in mind is to use the most suitable Equation of State (EOS), considering an accurate fluid description and to have a robust flash algorithm.

The reservoir fluid characterization procedure includes tuning of all the binary parameters of the EOS to match the experimental data including Bubble Point/ Saturation Pressure, Separator Test, Constant Composition Expansion and Liberation Tests, etc. In addition, SARA contents are often used for the Asphaltene and the Resin content in the fluid. AOP and asphaltene onset concentration (AOC) measurements for different operating conditions and injected fluid compositions are most importantly used for the asphaltic reservoir fluid characterization. The amount of precipitation at different temperature and pressure conditions can also be used, if available, for the sake of an extended fluid phase diagram.

The specific guidelines for the non-asphaltic and asphaltic reservoir fluid characterization are relatively simpler and commonly available in the literature i.e. also summarized as given below;

1.1. Non – Asphaltic Fluid Characterization

First, we use lumping and splitting procedures for different components of the reservoir fluid. The adopted procedure is listed below:

1. Lump all non-hydrocarbons separately.
2. Generate separate groups of C_1 - C_6 hydrocarbons.
3. Split heavier HCs (C_7+) in a way that each pseudo component ends up with approximately similar weight percentage.
4. Calculate the critical properties of all pseudo components based on the weighted mean average of each carbon number fraction.

Including non-hydrocarbon components, this procedure usually leads to seven to eight pseudo components in general. This lumping method is very general and the following additional, more specific guidelines have been presented by Khan¹⁹;

1. It's highly recommended to ignore the non-hydrocarbon components with the mole fractions less than 0.005, the only exception to this step is when the non-HC external fluid is being injected into the reservoir.
2. It was also advised to lump lighter hydrocarbon components i.e. C_1 to C_6 to be lumped as C_1 , C_{2-3} , and C_{4-6} . However, other combinations are also possible depending on their mole fractions.
3. It was also recommended using the following Table 1 as a guideline for splitting of the heavier HCs depending on the C_{7+} mole fraction.

Table 1: The recommended number of pseudo-components as a function of C_{7+} mole fraction

C_{7+} Mole Fraction	No. of Pseudo Components
< 0.05	1
0.05 – 0.4	2
0.4 – 0.6	3
0.6 – 0.8	4
> 0.8	5

1.2. Asphaltic Fluid Characterization

The characterization procedure for the asphaltic fluid includes tuning of all the parameters of the phase behavior model to reproduce the experimental data as close as possible to the lab experimental data. Darabi²⁰ provided detailed instructions for asphaltic fluid characterization:

1. Split the heaviest HC component into heavier fractions. As the reservoir fluid PVT data usually reported commercially up to C_{7+} fractions. However, the average molecular weight of asphaltene is larger than a typical C_{7+} component in a mixture, so that the HC components between C_{30} to C_{40+} could be a good representation of the asphaltene component.
2. Further split the heaviest HC component (e.g. C_{47+}) into two sub-components, i.e. a non-precipitating component (C_{47+A}) and a precipitating component (C_{47+B}). The precipitating component will be referred to as asphaltene. Whereas the properties of both the components would be identical, except for their binary interaction coefficients with the lighter components.²²
3. Decide on the EOS tuning parameters to be used as variables for matching the experimental measurements. In the case of asphaltic oils, the tuning parameters include:
 - a. Total number of lumping groups
 - b. Binary interaction coefficients (BIC)
 - c. Volume shift parameters
 - d. Molar volume of asphaltene.
4. Reduce the total number of components by lumping some of the middle components.
5. Calculate the phase behavior of the mixture.
6. Compare model predictions against the experimental measurements.
7. Through a trial and error process, keep modifying the EOS tuning parameters such that the calculated EOS phase behavior matches the measured data with the minimum uncertain error differences that shouldn't be more than 10%.
8. In case of unacceptable results, modify the middle order lumped components and repeat the stated above until find a good match with an acceptable error band.

III. EQUATION OF STATE TUNING

The EOS tuning is performed by matching the lab measurements for the following types of data:

1. Routine PVT including CCE and DL tests
2. Special PVT including CO_2 swelling and MMP measurement tests
3. Asphaltene precipitation and saturation pressures for each oil – CO_2 mixtures with different concentrations

To perform experiments, dead oil and gas samples were collected from the first stage separator sampling point in the field.

The collected samples were analyzed and recombined under average reservoir conditions on the basis of the Gas Oil Ratio (GOR) measured on bottom hole live oil samples i.e. 220scf/bbl. A single flash separation test was conducted on the recombined oil under atmospheric pressure and temperature conditions.

3.1 EOS Tuning with Routine PVT Lab Experiments

Based on the procedure described above, the subject reservoir fluid is characterized by using Peng Robinson Volume Translated (PR – VT). A commercial software was used to simulate routine PVT experiments. The results are in good agreements with the lab measurements as shown in the Figures 1 and 2 where perfect matches are obtained for the relative volume and liquid density different operating pressures. Figure 3 depicts a good match for the calculated and measured viscosity values. Also, the liquid formation volume factor and the solution gas-oil ratio are in good agreements with the measured data as shown in figures 4 and 5, respectively.

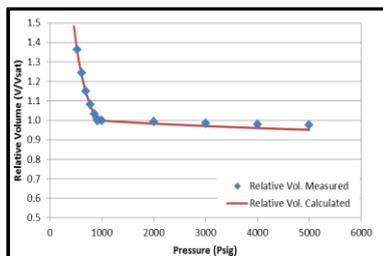


Fig. 1. Comparison of the measured and predicted Relative Volume

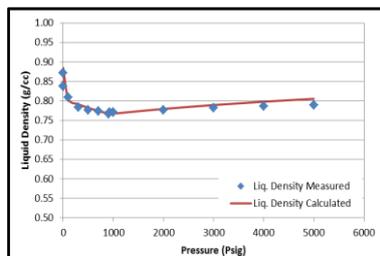


Fig. 2. Comparison of the measured and predicted values for the Liq. Density

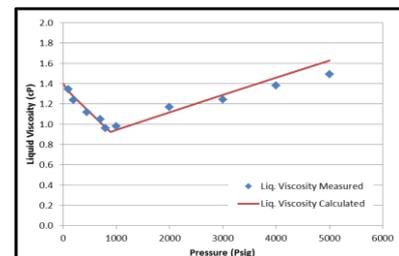


Fig. 3. Comparison of the measured and predicted Oil Viscosity

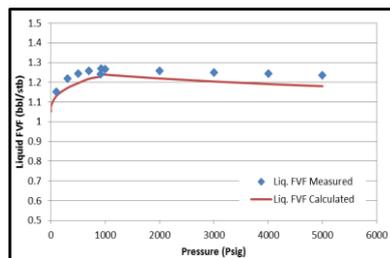


Fig. 4. Comparison of the measured and predicted Liquid Formation Vol. Factor (FVF)

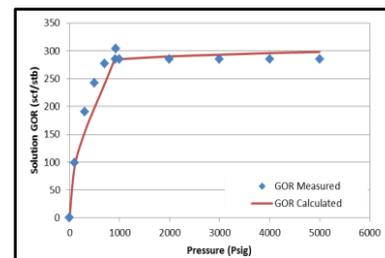


Fig. 5. Comparison of the measured and predicted Solution Gas-Oil Ratio (GOR)

3.2 EOS Tuning with Special PVT Tests

In the second phase, we have conducted special PVT tests to better understand the thermodynamics of reservoir fluid as a function of pressure and composition. In these tests, the saturation pressures and swelling factors are measured at different CO_2 concentrations. Figure 6 shows that the saturation pressures and swelling factors are both directly proportional to the CO_2 concentrations. A decent simulated match was obtained using the EOS that was generated in the previous step.

The relative volumes and liquid saturations were measured at different ratios of oil – CO_2 mixtures and pressures. Figures 7 and 8 show decent agreements between the experimental measurements and the simulated results using the tuned EOS. Similarly, we measured the liquid density and viscosity, and subsequently, compared them against the predicted results of tuned EOS model (see figures 9 and 10). The density matches for all mixtures are in good agreement with their experimental counterparts (within 2-5% error). This is contrary to the viscosity predictions. The model's accuracy for predicting liquid viscosity deteriorates at lower concentrations of CO_2 . This discrepancy could be as large as 5-10% which is still acceptable for our purposes.

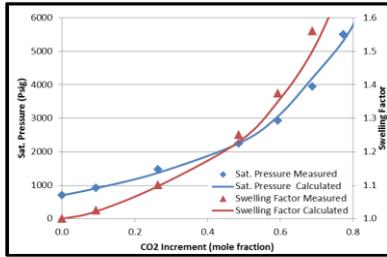


Fig. 6. Comparison of the measured and the predicted Saturation Pressure and Swelling Factor during CO₂ Injection at T_{res}

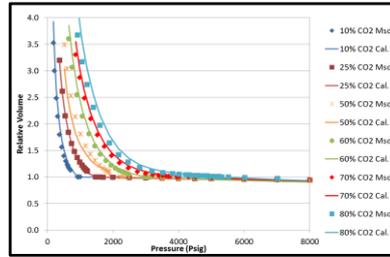


Fig. 7. Comparison of the measured and the predicted Rel. Vol. vs. Pres. for several Oil-CO₂ Mixtures at T_{res}

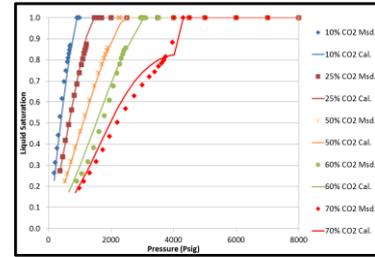


Fig. 8. Comparison of the measured and the predicted Liquid Saturation vs. Pressure for several Oil-CO₂ Mix. at T_{res}

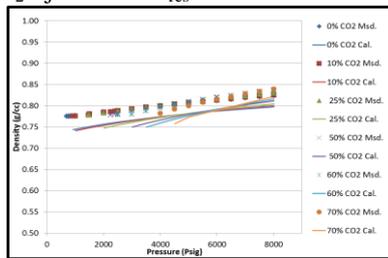


Fig. 9. Comparison of the measured and the predicted Density vs. Pressure for several CO₂ mixtures at T_{res}

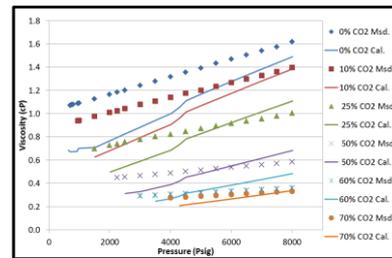


Fig. 10. Comparison of the measured and the predicted Viscosity vs. Pressure for several CO₂ mixtures at T_{res}

3.3 Tuning of the EOS using Asphaltene Onset Measurements

For an asphaltic fluid, the last phase of the thermodynamic characterizations is to tune the BICs, volume shift parameters, and molar volume of the asphaltene. We consider the fact that the BICs of asphaltene and the lighter hydrocarbon components are often higher due to the larger difference in their molecular structures. All parameters are tuned using an trial-and-error procedure to minimize the discrepancy with the measured experimental data.

Fig. 11 shows an excellent match of the saturation pressure and the asphaltene onset pressures at various CO₂ concentrations under reservoir temperature and pressure conditions. It is worth mentioning that the EOS of this work is only tuned using CO₂ as an injectant fluid so it might not work accurately for other HC or non-HC injectant gases.

The asphaltene precipitation envelopes for different concentrations of oil – CO₂ mixtures are shown in Figure 12. For each data set, the lowest pressure represents asphaltene's onset point. The peaks of the curves correspond to the saturation pressures. The highest pressure for any curve represents the asphaltene offset point. For example, reservoir oil with 50% of CO₂ mole fraction represented by the red curve, shows the asphaltene onset pressure of about 1600 Psi, saturation pressure at 2150 Psi, and the offset pressure at 4400 psi. To put numbers in perspective, the case with 0% CO₂ shows a negligible amount of precipitation which is almost considered as no asphaltene activity, i.e., thermodynamically stable in the absence of CO₂ phase.

A couple of important observations are made:

- As CO₂ mole fraction increases the saturation pressure rises constantly
- The presence of CO₂ shifts the entire asphaltene precipitation envelop towards higher pressure and at the same time, it expands the asphaltene instability region to a large extent.

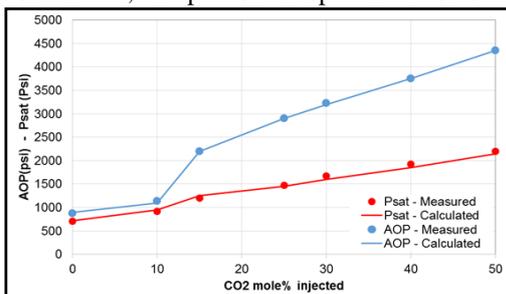


Fig. 11. Comparison of the measured and predicted AOPs and P_{sat} for several Oil – CO₂ mixtures at T_{res}

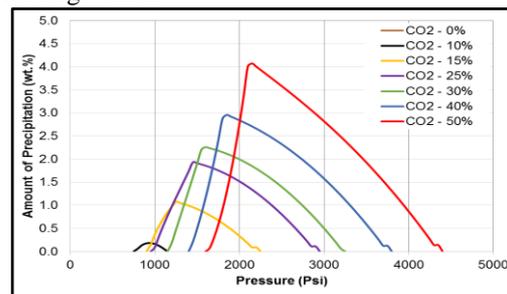


Fig. 12. Asphaltene Precipitation Envelop at Different CO₂ Mole Fractions at T_{res}

IV. PROOF OF EQUATION OF STATE VALIDATION

The tuned EOS was subsequently used to simulate the actual CO₂ core flooding experiment conducted under reservoir conditions. For this experiment, we used a composite core sample consisting of 4 different core plugs with similar rock properties wrapped by a shrinkage tube. The dimensions of the composite core were $0.716 \times 0.125 \times 0.125$ ft³. Table 2 summarizes the properties of the composite core sample and simulation parameters. We measured the porosity and permeability of one of the rock samples (i.e., 25% and 4.725 mD). For simulation, we used these measured values as the mean values of distributions along the main flow direction of the composite core sample (see Figs. 13 and 14). The simulations were done using a non-isothermal dynamic compositional academic reservoir simulator. In the laboratory, CO₂ was injected with a constant flow rate from the inlet. A back pressure regulator was used at the outlet to keep the outlet pressure constant. Same boundary conditions were implemented in our simulation.

Table 2: The experimental and modeling properties used in this study

Parameters	Value
No. of grid-blocks	20 × 1 × 1
Composite Core Dimension	0.716 ft. × 0.125 ft. × 0.125 ft.
Temperature	212 °F
Pressure	3000 Psi
Initial Water Saturation	0.20
Average Composite Porosity	0.25
Average Composite Permeability	4.725 mD
Injection Fluid	CO ₂
Inlet Conditions	Fixed Inj. Rate = 0.1 cc/min
Outlet Condition	Fixed Outlet pressure = 3000 Psi

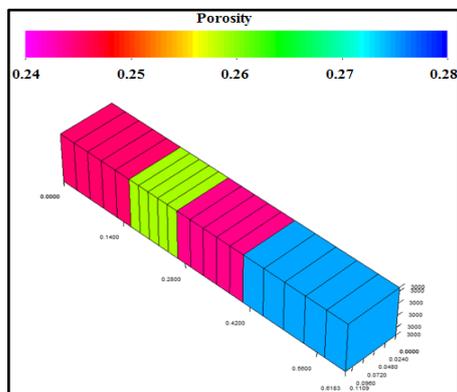


Fig. 13. Porosity Distribution Used for Simulation Purposes

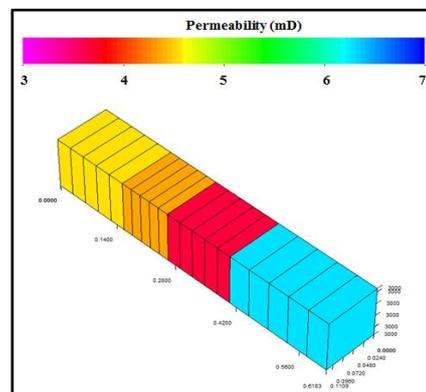


Fig. 14. Permeability Distribution Used for Simulation Purposes

More detail of the core flood design is provided by Syed¹. In the lab, two different types of data were collected, i.e., total oil recovery versus time and differential pressures along the length of the composite core. The latter was collected by using multiple pressure taps along the core holder. At the end of the experiment, 4 pore volume of CO₂ was injected resulting in an oil recovery of almost 85% (Fig. 15).

We tuned the relative permeability endpoints to match the core-flooding experimental measurements specifically oil recovery and GOR. As shown in Fig. 15, the model successfully captures the experimental measurements of oil recovery as a function of cumulative injected CO₂. Moreover, the GOR is within $\pm 10\%$ of the experimental data, as shown in Fig. 16. Figs. 17 through 19 depict the oil saturation distribution at different pore volumes of the injected CO₂. The inhomogeneity of rock properties along the main flow direction caused a considerable amount of oil to be trapped in the middle of the core. The distributions of asphaltene precipitation and deposition along the core are shown in Figs. 20 and 21 for different PVs of the injected CO₂. At the beginning of CO₂ injection, most precipitations occur close to the injector side. As the CO₂ penetrates deeper into the core, it causes deeper precipitations towards the producer side.

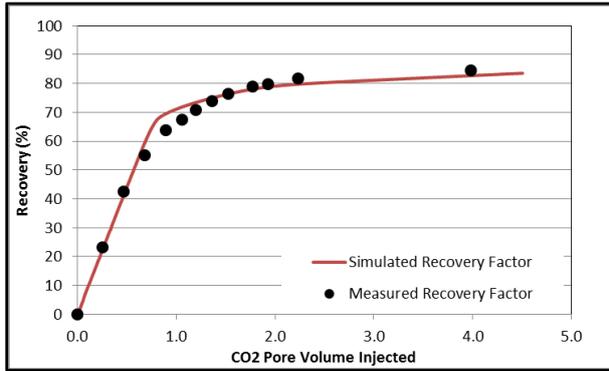


Fig. 15. Comparison of the measured and Simulated Oil Recovery during CO₂ injection

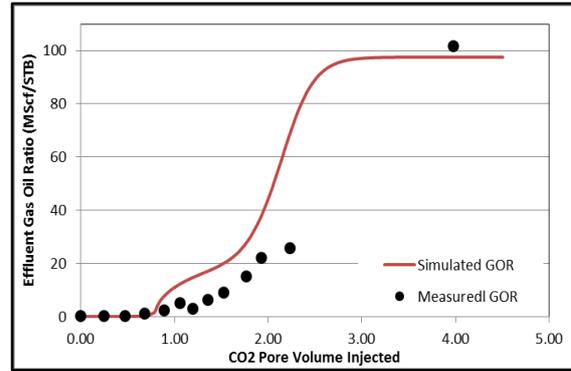


Fig. 16. Comparison of the measured and Simulated Gas Oil Ratio

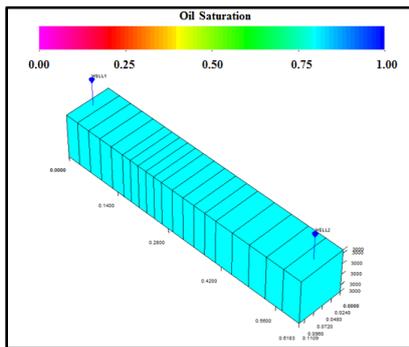


Fig. 17. Initial oil saturation before CO₂ injection

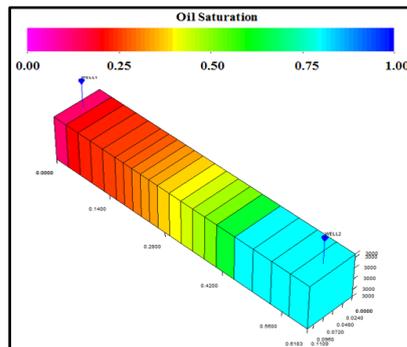


Fig. 18. Oil saturation after 1 PV of CO₂ injection

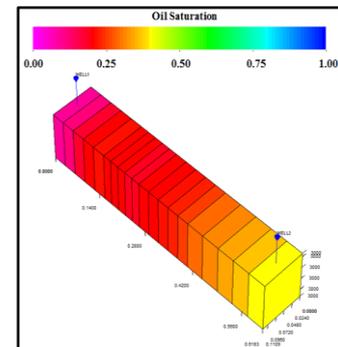


Fig. 19. Oil saturation after 2 PV of CO₂ injection

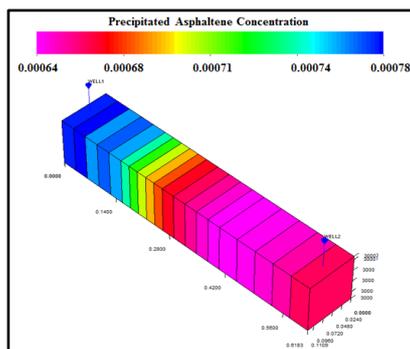


Fig. 20. The concentration of Precipitated Asphaltene after 1 PV of CO₂ injection

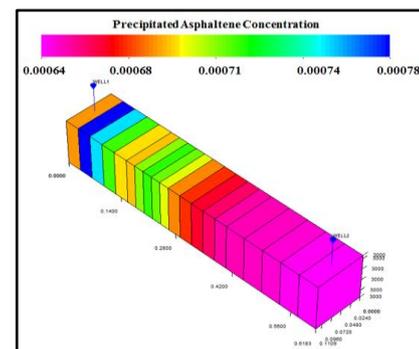


Fig. 21. The concentration of Precipitated Asphaltene after 2 PV of CO₂ injection

V. SUMMARY & CONCLUSION

A complete suite of experimental dataset covering the routine and special PVT analysis as well as asphaltene onset pressure for different compositions of the reservoir oil with CO₂ is presented. A fluid characterization procedure is explained in details for an asphaltic and non-asphaltic reservoir oil; and subsequently, a tuned EOS was developed by using laboratory-measured data. The tuned EOS was then utilized to predict the experimental measurements of a CO₂ flooding experiment performed on a long composite core sample. The predicted results were found to be in a good agreement with the actual core-flooding measurements. This work can be further expanded by designing a 3D sector model to specifically characterize contributions from different parts of the reservoir (i.e., wellbore, near-wellbore, and deep into the reservoir formation).

ACKNOWLEDGMENTS

The authors would like to thank ADNOC Offshore, UAE and the Department of Chemical and Petroleum Engineering, University of Kansas, USA for providing their support and permission to publish this work.

NOMENCLATURE

AOC	Asphaltene Onset Concentration
AOP	Asphaltene Onset Pressure
BICs	Binary Interaction Coefficients
CCE	Constant Composition Expansion Test
DL	Differential Liberation Test
EOS	Equation of State
HCs	Hydrocarbons
PR-VT	Peng Robinson Volume Translated
PTSD	Pore Throat Size Distribution
S _{or}	Residual Oil Saturation

REFERENCES

- [1]. Syed FI, Ghedan SG, Hage AR, Tariq SM, Shebl H. Formation flow impairment in carbonate reservoirs due to asphaltene precipitation and deposition during hydrocarbon gas flooding. In: Society of Petroleum Engineers - Abu Dhabi International Petroleum Exhibition and Conference 2012, ADIPEC 2012 - Sustainable Energy Growth: People, Responsibility, and Innovation. Vol 1. ; 2012.
- [2]. Gonzalez DL, Ting PD, Hirasaki GJ, Chapman WG. Prediction of Asphaltene Instability under Gas Injection with the PC-SAFT Equation of State. *Energy & Fuels*. 2005;19(4):1230-1234. doi:10.1021/ef049782y
- [3]. M. Vargas F, Gonzalez D, Hirasaki G, Chapman W. Modeling Asphaltene Phase Behavior in Crude Oil Systems Using the Perturbed Chain Form of the Statistical Associating Fluid Theory (PC-SAFT) Equation of State†. Vol 23.; 2009. doi:10.1021/ef8006678
- [4]. Torkaman M, Bahrami M, Dehghani MR. Influence of Temperature on Aggregation and Stability of Asphaltenes. II. Orthokinetic Aggregation. *Energy & Fuels*. 2018;32(5):6144-6154. doi:10.1021/acs.energyfuels.7b03601
- [5]. Mousavi-Dehghani SA, Riazi MR, Vafaie-Sefti M, Mansoori GA. An analysis of methods for determination of onsets of asphaltene phase separations. *J Pet Sci Eng*. 2004;42(2):145-156. doi:https://doi.org/10.1016/j.petrol.2003.12.007
- [6]. Liao Z, Geng A. Asphaltenes in oil reservoir recovery. *Chinese Sci Bull*. 2000;45(8):682-688. doi:10.1007/BF02886171
- [7]. Leontaritis KJ, Amaefule JO, Charles RE. A Systematic Approach for the Prevention and Treatment of Formation Damage Caused by Asphaltene Deposition. *SPE Prod Facil*. 1994;9(03):157-164. doi:10.2118/23810-PA
- [8]. M. Butler R, J. Mokrys I. Recovery Of Heavy Oils Using Vaporized Hydrocarbon Solvents: Further Development Of The Vapex Process. Vol 32.; 1993. doi:10.2118/93-06-06
- [9]. dePedroza TM, Calderon G, Rico A. Impact of Asphaltene Presence in Some Rock Properties. *SPE AdvTechnol Ser*. 1996;4(01):185-191. doi:10.2118/27069-PA
- [10]. Minssieux L. Core Damage From Crude Asphaltene Deposition. *IntSympOilf Chem*. 1997;19. doi:10.2118/37250-MS
- [11]. Kamath VA, Yang J, Sharma GD. Effect of Asphaltene Deposition on Dynamic Displacements of Oil by Water. *SPE West Reg Meet*. 1993;9. doi:10.2118/26046-MS
- [12]. Gonzalez G, Travalloni-Louvisse AM. Adsorption of Asphaltenes and Its Effect on Oil Production. *SPE Prod Facil*. 1993;8(02):91-96. doi:10.2118/21039-PA
- [13]. Fahad I. Syed, Tunio A. Haque NG. Compositional Analysis & Screening for EOR Processes in Different Reservoirs & Operating Condition. *Int J ApplSci Technol*. 2011;1(4):143-160.
- [14]. Fahad I. S.; Ahmed A. K. Lean HC Gas Injection Pilots Analysis and IPR Back Calculation to Examine the Impact of Asphaltene Deposition on Flow Performance. *J Pet Res Elsevier*. 2018;3(4).
- [15]. Peramanu S, Singh C, Agrawala M, Yarranton HW. Investigation on the Reversibility of Asphaltene Precipitation. *Energy & Fuels*. 2001;15(4):910-917. doi:10.1021/ef010002k
- [16]. de Boer RB, Leerlooyter K, Eigner MRP, van Bergen ARD. Screening of Crude Oils for Asphalt Precipitation: Theory, Practice, and the Selection of Inhibitors. *SPE Prod Facil*. 1995;10(01):55-61. doi:10.2118/24987-PA
- [17]. Abdolvahab R. RK. Investigation of Asphaltene Deposition and Precipitation in Production Tubing. *Int J Clean Coal Energy*. 2017;6(1):14-29.
- [18]. Almehaideb RA. Asphaltene precipitation and deposition in the near-wellbore region: a modeling approach. *J Pet Sci Eng*. 2004;42(2):157-170. doi:https://doi.org/10.1016/j.petrol.2003.12.008
- [19]. Khan, Sameer Ali. An expert system to aid in compositional simulation of miscible gas flooding. Diss. University of Texas at Austin, 1992.
- [20]. Darabi H, Abouie A, Sepehrmoori K. Effect of Temperature Variations on Asphaltene Dynamics in Oil Reservoirs. *SPE West Reg Meet*. 2016;15. doi:10.2118/180481-MS
- [21]. Syed, F. I., Boukhatem, M., & Al Kiyoumi, A. A. (2019). Lean HC gas injection pilots analysis and IPR back-calculation to examine the impact of asphaltene deposition on flow performance. *Petroleum Research*, 4(1), 84-95.
- [22]. Nghiem, L. X., Hassam, M. S., Nutakki, R., & George, A. E. D. (1993, January). Efficient modeling of asphaltene precipitation. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.

Fahad I. Syed, ET. Al " An Experimental and Numerical Study of Asphaltene-Induced Formation Damage during CO₂ Miscible Flooding". *American Journal of Engineering Research (AJER)*, vol. 9(03), 2020, pp. 60-67.