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# The impact of asphaltene deposition on fluid flow in sandstone

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ABSTRACT

Asphaltene deposition in oil reservoirs is a contentious issue affecting both well and reservoir productivity. Though the phenomenon has been previously studied in several laboratory experiments, the uniformity aspects of the asphaltene deposit are usually overlooked. We have previously developed an experimental workflow to create a uniform deposit of asphaltene inside the core sample. In this study, the impact of this uniform deposit on fluid flow is quantified through imbibition, corefloods and relative permeability experiments. In addition, the lab results are used in a field scale simulation to investigate the impact of deposition on field performance. The results exhibit a shift in the wettability state where a reduction in both water imbibition rate and capacity are observed after deposition. Besides, up to 25% reduction in absolute permeability is detected. Results of pressure drop experiments across the core conducted on the exposed rocks indicate a change in the wetting characteristics, with the exposed rocks becoming more mixed/intermediate wet and varying with the change in the initial brine saturation in the rock. Subsequently, the relative permeability set is affected where a shift in the oil residual saturation, a downgrade in the oil curve and an upgrade in the water curve are observed. Upscaling this new data to field scale indicated a loss of more than half of the well productivity and an earlier breakthrough if waterflooding is implemented.

## 1. Introduction

Asphaltenes characterization and stability is a topic of continuous importance to the petroleum industry. Asphaltenes constitute the most polar fraction of crude oil (Denekas et al., 1959) with an undefined molecular weight or structure (Groenzin et al., 2003; Strausz et al., 1992). They are usually defined as a solubility class, where asphaltenes are soluble in light aromatics such as benzene and toluene, and insoluble in light aliphatic like pentane and heptane (Buenrostro-Gonzalez et al., 2001; Mitchell and Speight, 1973; Speight et al., 1982, 1984). The deposition of these molecules could be triggered by disturbing the equilibrium state through either a change in the physical conditions or the composition (Cho et al., 2016).

Several thermodynamics models have been proposed to study asphaltene stability. Some advocate the colloidal nature of asphaltene, where the precipitation is caused by micelle flocculation, and others advocate the molecular nature of asphaltene where precipitation happens conventionally. For instance, Leontaritis and Mansoori assumed asphaltene molecules are suspended solid particles peptized by resin molecules present in the mixture (Leontaritis and Mansoori, 1987). On the other hand, Wang and Buckley proposed a two-component solubility model to predict the onset of asphaltene flocculation (Mitchell and Speight, 1973).

The permeability impairment induced by asphaltene deposition is evident in several experimental studies (Kocabas, 2003; Zekri and Almehaideb, 2001; Shedid, 2004). Minssieux (1997) conducted core flood experiments on sandstone samples using different crude oils where a 20–90% drop in the absolute permeability to cyclohexane is observed. They analyzed the asphaltene content of oil at both the inlet and effluent streams when they inferred that the permeability impairment was indeed due to asphaltene deposition. Hamadou et al. (2008) focused on quantifying the damage in the absolute permeability of the Berea and Rhourd-Nouss cores where Soltrol was injected to both displace the crude oil and measure the initial and final permeability. In addition, they correlated the extent of damage to the iron content of the core, where a negative relationship was observed with a reduction in the possible damage occurring in the cores with a higher iron content. This relationship was also validated by Jafari Behbahani et al., 2013 who observed the same trend, besides a positive relationship between the calcite content and the extent of deposition. The deposition of asphaltene in carbonate rocks is evident. Kord et al. (2012) used both live and dead oil samples to study the deposition of asphaltene where they reported an exponential behavior for the impact of deposition on permeability damage and a linear behavior for pore plugging.

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**Table 1**
Cores dimensions and properties.

| Purpose | Cores | L (in) | D (in) | W (gm) | ϕ (%) | K(md) | Process |
|---|---|---|---|---|---|---|---|
| Spontaneous Imbibition | GB-J2-1 | 1.958 | 0.999 | 51.97 | 22.49 | – | Control- DI/Hep/DI |
| | GB-J2-2 | 1.899 | 0.996 | 50.45 | 22.42 | 125 | Exposed to crude-DI/Hep |
| | GB-J2-4 | 1.984 | 1.000 | 53.06 | 22.20 | 133 | Exposed to crude-Hep/DI |
| Pressure Drop Test | GB-J9-3 | 1.954 | 0.996 | 53.23 | 19.88 | 105 | Control -Brine Injection- Heptane Injection |
| | GB-J6-3 | 1.990 | 0.985 | 52.69 | 19.88 | 107 | Vacuum Saturated– Heptane Flush- Dried- Brine Injection- Heptane Injection |
| | GB-J6-2 | 1.928 | 0.986 | 51.00 | 19.25 | 117 | Vacuum Saturated–Heptane/crude slugs (4:1 PV) - Heptane/crude co-injection– Heptane Flush- Dried- Brine Injection- Heptane Injection |
| | GB-J9-2 | 1.844 | 0.998 | 49.90 | 20.77 | 118 | Crude Injection– Heptane Flush- Dried- Brine Injection- Heptane Injection |
| Relative Perm | GB-J7-1 | 5.960 | 0.992 | 159.70 | 20.11 | 135 | Clean |
| | GB-J10-1 | 5.992 | 0.999 | 163.48 | 19.86 | – | Saturated |

Asphaltene deposition has been modeled at both the well and the reservoir scales. Almehaideb (2004) developed a four-component single well model where both the distribution of precipitated asphaltene molecules and the permeability and porosity reduction induced by plugging and deposition are reported. Shirdel et al. (2012) critically reviewed the current deposition models for asphaltene. Mohebbinia et al. (2017) used PC-SAFT EOS to properly simulate the asphaltene deposition. Further developments in the understanding of asphaltene include using a support vector machine to develop a model for asphaltene precipitation (Ansari and Gholami, 2015), computational fluid dynamics to study the deposition of asphaltene molecules (Haghshenasfard and Hooman, 2015; Seyyedbagheri and Mirzayi, 2017), and molecular simulation to study the interactions among these molecules (Yaseen and Mansoori, 2017).

The relation between rock wettability and asphaltene deposition is the focus of many research studies (Anderson, 1986, 1987). Al-Maamari and Buckley (2000) experimentally studied the relation between asphaltene stability and the wetting nature of mica surfaces where the oil wetting nature increased for the majority of the crudes tested. Uetani (2014) observed an increase in the water cut after the asphaltene onset, which could be attributed to an enhanced oil wetting state induced by asphaltene deposition. Mirzayi et al. (2008) also studied the alteration of rock wettability by determining the reduction in the irreducible water after crude injection, decreased from 26.5% to 10.7%. However, they did not take into account the effect of the non-uniform deposition on the flow behavior. Wolcott et al. (1996) tested and quantified this wettability change using Amott's imbibition tests where they related the extent of wettability alteration to the content of asphaltene and resin, as well as the aging period.

Limited studies were also conducted on the effect of asphaltene deposition on two phase flow behavior and its impact at a reservoir scale. Hematfar et al. (2013) performed several experiments on sand packs with asphaltene from Canada, and observed a shift in the relative permeability endpoints, corresponding to the adsorption of asphaltenes onto the surface. Similar results were also obtained by Shedid (2001) who studied the deposition of asphaltene in carbonate rocks with crudes of different asphaltene contents. It was observed that the relative permeability end points are shifted further depending on the asphaltene content, with the crude having a higher asphaltene content showing lower irreducible water saturation. Nasri and Dabir (2009) upscaled the effect of relative permeability shifts to a field scale where they observed a reduction in both the cumulative oil production and the bottom hole pressure and that the extent of this drop was dependent on the asphaltene content of the crude.

Most of the experimental work cited acknowledges the non-uniformity aspect of the deposition, where the inlet of the core experiences a larger drop in permeability; however, that literature does not note the need for a uniform asphaltene deposition so that meaningful relative permeability data can be collected. When a core experiences a gradient in permeability change between the inlet and outlet due to the non-uniform deposit of asphaltene, the measured flow and pressure data cannot be reliably translated into usable relative permeability data that can be used in simulation efforts. In this work, the impact of uniform asphaltene deposition on both reservoir characteristics and fluid mobility is quantified. The uniformity of the asphaltene deposit is what distinguishes our work from previous attempts towards such measurements. The rest of this paper is organized as follows; in the material and methodology section, both rocks and fluids used are presented along with the experimental procedure and the simulation details. In the results and discussion section, the impact of deposition on imbibition and pressure drop is analyzed. After that, the permeability impairment associated with the deposition is investigated, and subsequently, the results are implemented in a field scale study. Finally, the main findings and concluding remarks are summarized in the conclusions section.

## 2. Materials and methods

### 2.1. Rocks and fluids

Berea sandstones cores are used with a diameter of one inch, and a length ranging from one to six inches. Air coring is implemented, as the rocks are prone to clay swelling. The cored samples are polished to achieve a flat surface and their dimensions are then measured. The porosity of the cores is measured using a porosimeter based on Boyle's law with helium expansion. Once the porosity is measured, the absolute permeability of the cores is estimated using a nitrgoen gas permeameter under a confining pressure of 1500 psi. The rock properties and dimensions are reported in Table 1.

The crude oil used in these experiments is obtained from a wellhead in Texas. The asphaltene content is measured using a modified form of the ASTM IP143 Standard for the Determination of asphaltenes in Crude Petroleum (Goual and Firoozabadi, 2004). Two grams of oil are mixed with 80 g of heptane and heated to accelerate asphaltene aggregation. The sample is then passed through a filter paper under vacuum. The deposit is dissolved in toluene and then evaporated to measure the amount of asphaltene in the sample. Brine with 3 wt% NaCL is used to suppress clay swelling experienced with fresh water. In addition, heptane is used as a displacement fluid, as it is not a solvent to the asphaltenes. Toluene is used mainly for cleaning the setup, during the asphaltene content filtration test, as well as to remove the asphaltene deposition. Helium and nitrogen are used to measure the porosity and permeability respectively. The fluid properties are summarized in Table 2.

### 2.2. Experimental procedures

Previously, we investigated the uniformity of the asphaltene deposit where the deposit established through vacuum-saturating the cores exhibits more uniform distribution than asphaltene deposit through injecting oil into the cores (James et al., 2018). In this work, we utilized the protocol established in that publication to study the impact of asphaltene deposits on fluid flow using imbibition and core flood

**Table 2**
Fluids Used, and their Properties (at 20 °C).

| Fluid | Density (g/cm$^3$) | Viscosity (cp.) |
|---|---|---|
| Texas Crude[a] | 0.884 | 19 |
| Brine | 1.021 | 1.32 |
| Heptane | 0.684 | 0.376 |
| Toluene | 0.865 | 0.560 |
| Deionized Water | 1 | 1 |

[a] Asphaltene content: 0.85 ± 0.2 wt%.

experiments. This step was identified as essential so that meaningful macroscopic flow data can be collected and analyzed. The imbibition experiments are conducted on the cores utilizing two imbibition cycles. Oil-saturated cores are dried for a day after flushing it with heptane. The imbibition tests involve alternating water and heptane cycles into air-saturated cores, separated by 1 day of drying. The weight change of the submerged cores is used to monitor the progress of imbibition. On a different set of cores, pressure drop is recorded during brine and heptane flooding.

Relative permeability is estimated to evaluate the impact of the asphaltene deposit on the mobility of fluids. Six-inch cores are used for these experiments. Brine and heptane are injected in a varying sequence (total flow rate is less than 2 cc/min) to obtain the end points of the relative permeability curves. Stones' correlations are used in order to generate the relative permeability graphs given the measured end-point data.

### 2.3. Simulation details

The lab results are implemented at the field scale using a black-oil model; in such model, three phases are considered (oil, gas and water) where the compositional changes are insignificant. The reservoir extends 2500 ft X 2500 ft and properties are listed in Table 3. The impact of asphaltene deposition is incorporated by adopting the damaged core relative permeability curves along with a 10% reduction in the absolute permeability. The reservoir model includes one injector, whose rate is constrained to 1000 bbl/day, and one producer, whose bottom-hole pressure is constrained to 2000 psi, placed at the corners. The injection well is rate-constrained. Our model is layered, where the water is injected from the bottom and the oil is produced from the top. We designed our simulation scenario as a water flood where we could quantify the changes in the multiphase flow characteristics and its impact on productivity. In addition, we differentiated between the damage resulting from the absolute permeability and the damage resulting from relative permeability. This is manifested by simulating a scenario where the absolute permeability is the only modified parameter and another where the relative permeability is the only modified scenario, after that the performance of these scenarios is compared to the overall performance where both absolute and relative permeability damage are incorporated.

**Table 3**
The input parameters used for imulation

| Input | Value | |
|---|---|---|
| | Native | Exposed |
| Reservoir dimensions (grids) | 50 × 50 x 3 | |
| Grid dimensions (ft) | 50 × 50 x 50 | |
| Porosity (fraction) | 0.2 | |
| Horizontal Permeability (md) | 100 | 90 |
| Vertical Permeability (md) | 50 | 45 |
| Oil specific gravity | 0.684 | |
| Water Saturation (fraction) | 0.16 | 0.14 |
| Initial Reservoir Pressure (psi) | 5000 | |
| Reservoir Temperature (F) | 180 | |

## 3. Results and discussions

In this section, the impact of the deposition on spontaneous imbibition, pressure drop during core flooding, and relative permeability is presented. After that, results are used in a field example.

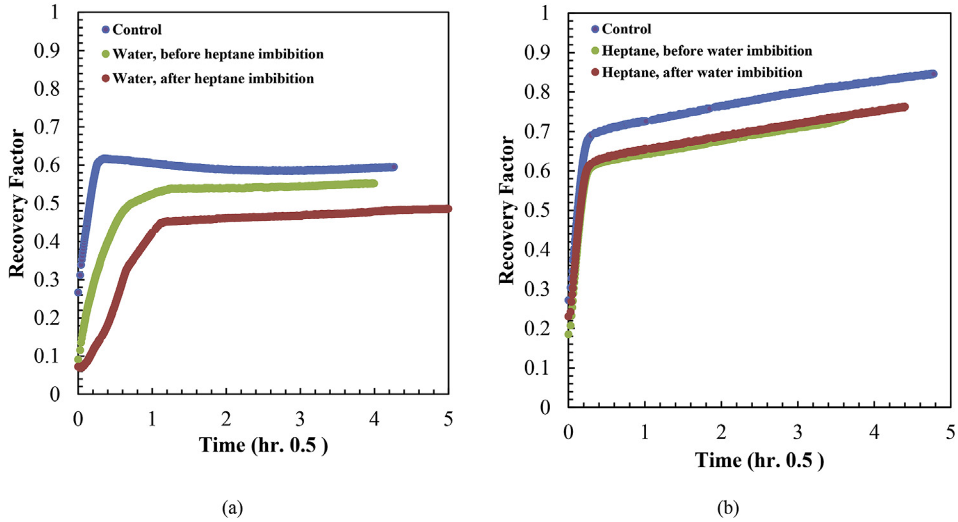
### 3.1. Imbibition results

As a dynamic measure of the wettability state of the rock, imbibition experiments are conducted on dry cores that have been vacuum-saturated with crude oil, aged, and flooded with heptane then dried. The results as presented in Fig. 1. While, the initial imbibition rate is controlled by capillary suction, the imbibition capacity indicates the accessible pore volume (Mehana et al., 2017, 2018). It is clearly observed that the heptane imbibition behavior experiences two distinct early and late imbibition rates for a given rock sample. With clear variations in the initial rate, the late rate is relatively the same for all the heptane cases considered. On the other hand, the water imbibition behavior experiences a relatively slower initial rate with a late rate close to zero. This behavior can be attributed to the lower density and viscosity of heptane compared to water, which results in both a faster imbibition of heptane and a larger accessible pore volume as the trapped gas could easily induce counter-current flow.

Both the reduction in the initial imbibition rate and capacity in the case of the water compared to the control sample reflects the damage induced by asphaltene deposition in its impact on permeability and wettability. While the reduction imbibition rate indicates a shift in the water wetting nature of the rock towards reduced water-wetting, the reduction in the imbibition capacity indicates the conductivity damage induced. In addition, the reduction in the imbibition capacity for heptane in the second cycle compared to the control indicates the damage to the flow capacity of the rock. The non-monotonic behavior of water imbibition in the control run presented in Fig. 2 was attributed in our earlier work to clay swelling (Mehana et al., 2018). Interestingly, both water imbibition tests performed for rocks that were exposed to oil do not show such a signature although fresh water was used in the tests. This is an indication that clay particles had less access to the imbibed water. Exposure to heptane reduced the water wetting nature even more as shown in Fig. 2, while exposure to water did not affect the heptane imbibition as shown in Fig. 2.

### 3.2. Pressure drop

A reduction in the pressure drop during brine injection experiments is observed when the core is exposed to crude oil compared to the reference case, which implies a shift in the wetting nature of the rock. This shift increases when more deposition is introduced to the system by vacuum saturating the core or vacuum saturating followed by slug and co-injection of heptane/crude oil (both cases were aged). The hump in the pressure drop curves is usually observed when the wetting-phase is injected. The further the hump decreased, the more the wetting nature has shifted. Fig. 2 displays the pressure drop across the core for both brine and heptane injection, along with the brine saturation value at the end of the last round of heptane injection. The saturation history of the rock is also noted in the legend of the figure. The native rock has close to 30% irreducible water, while a drop to 20% irreducible water is observed for rocks exposed to crude. The rock experiencing the least resistance to heptane injection is the one that was exposed to crude using vacuum-saturation. This reduction in pressure is attributed to the decrease in capillary pressure and not an increase in oil mobility. This set of data asserts the findings from the imbibition tests, reflecting a reduced state of water-wetting. Rocks exposed to water before crude saturation show less change in their wetting nature as seen in the case of GB-J9-2.




(a)    (b)

**Fig. 1.** The imbibition results: a) water Imbibition b) oil Imbibition.

### 3.3. Permeability impairment

The impact of asphaltene deposition on rock conductivity is reported by quantifying both the absolute permeability loss and the shift in the relative permeability curves. Larger damage is reported for samples where asphaltene deposition is induced by injection compared to the vacuum-statured ones as shown in Fig. 3. Comparing this result to the TOC distribution in vacuum-statured cores implies that asphaltene deposition in vacuum-saturated cores is more distributed in the pore body compared to the injected cores where more asphaltene is concentrated in the pore throats as illustrated in the back-injection results of James et al. (2018).

The relative permeability curves for one of the vacuum-statured cores is compared to the native curves in Fig. 4. A shift in the end-points of the curve clearly indicates a change in flow behavior. While a significant increase is observed in the critical oil saturation, the critical water saturation is not affected. In addition, the water curve is boosted and the oil curve is suppressed. A reduction in the saturation window that allows both phases to be mobile was observed for the altered curves. All these indicators support the conclusion that the distributed asphaltene deposit impairs relative permeability.

### 3.4. Simulation results

The oil saturation maps for both the native and the altered models at the end of the simulation time are presented in Fig. 5. According to the

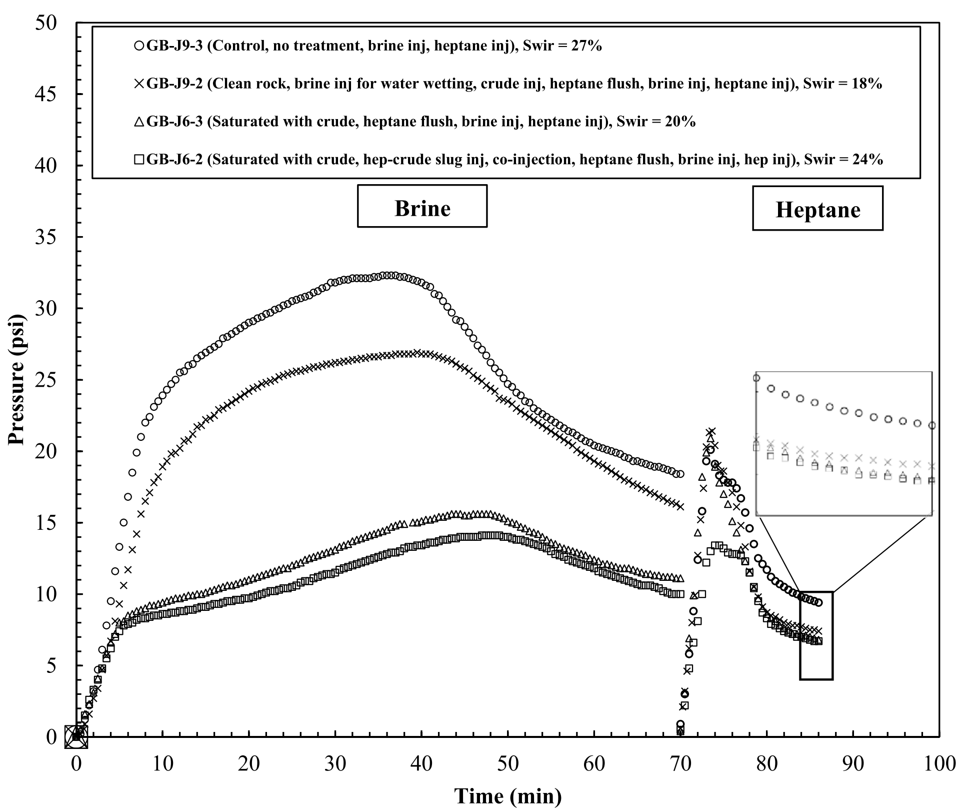



**Fig. 2.** Pressure drop across the core for both brine and heptane injection.

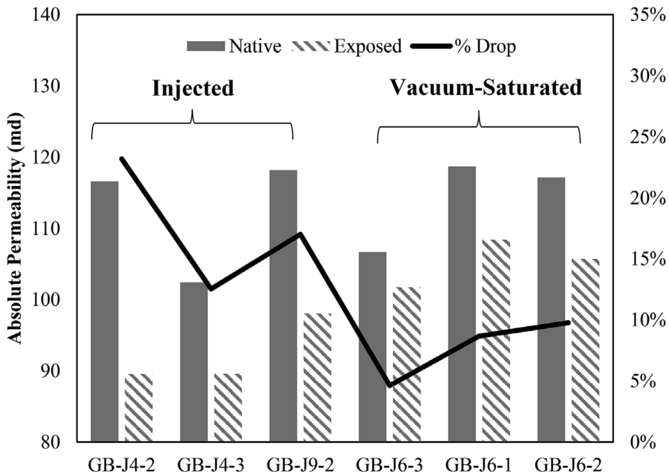



**Fig. 3.** Permeability damage for injected and vacuum-saturated cores.

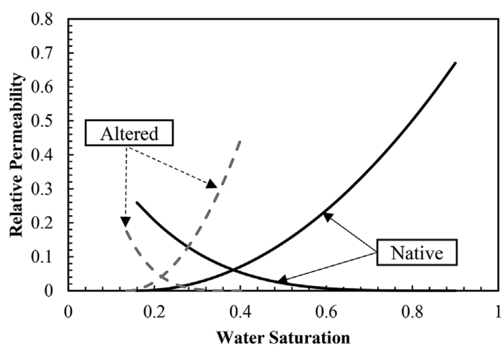



**Fig. 4.** The smoothed relative permeability for both clean and exposed cores.

simulation results, more than half of the well's productivity is lost due to the asphaltene deposition as presented in Fig. 6. In addition, early break through is observed for the altered case. However, this could be intuitively predicted considering the residual oil saturation and the enhanced water mobility used in the relative permeability curves. The impact of the absolute permeability reduction on well productivity is negligible compared to relative permeability. The accompanying increase in the injection pressure with the asphaltene deposition, reported in Fig. 7, highlights the detrimental impact of asphaltene deposition on water flooding. It is worth noting that we considered the relative permeability damage in the whole reservoir, not only near the wellbore. Recalling our experimental observations, asphaltenes are depositing throughout the core by just introducing the crude to the rock. This means that the flow of oil in porous media by itself would result in deposition. Herein, we are trying to upscale this observation by adopting the damaged relative permeability for the whole reservoir.

## 4. Conclusions

In this study, the precipitation of asphaltenes in Grey Berea rock samples, and its impact on rock characteristics are studied. The following are our main findings:

- Permeability impairment is up to 25% for cores where the deposition is introduced by continuous injection and 15% for cores where the deposition is introduced by vacuum saturating the core. Given that vacuum saturation results in uniform deposition, meaningful relative permeability data must be collected using these samples and not using cores where a non-uniform deposit is achieved.
- A change in the wetting properties is evident, with the cores become more neutral or oil wet based on imbibition and injection tests, when exposed to crude and the precipitated asphaltenes. This was greatly dependent on the initial brine saturation in the rock, where those rocks exposed to brine show a state of mixed wetting. Obtaining relative permeability data from cores that do not have an initial water saturation can be misleading on the extent of wettability alteration achieved.
- A reduction in clay swelling is observed in rocks exposed to crude oil
- Relative permeability end-points are determined experimentally where a higher irreducible oil saturation is observed for the exposed cores. One major finding to note in this case is the reduction in the width of the saturation window where both water and oil mobility is possible.
- Incorporating the formation damage in a reservoir simulator anticipates productivity loss of more than half of the well's potential. In addition, both earlier breakthrough time and higher injection pressure are expected due to asphaltene precipitation in the reservoir. Our decoupling of the impact of absolute permeability

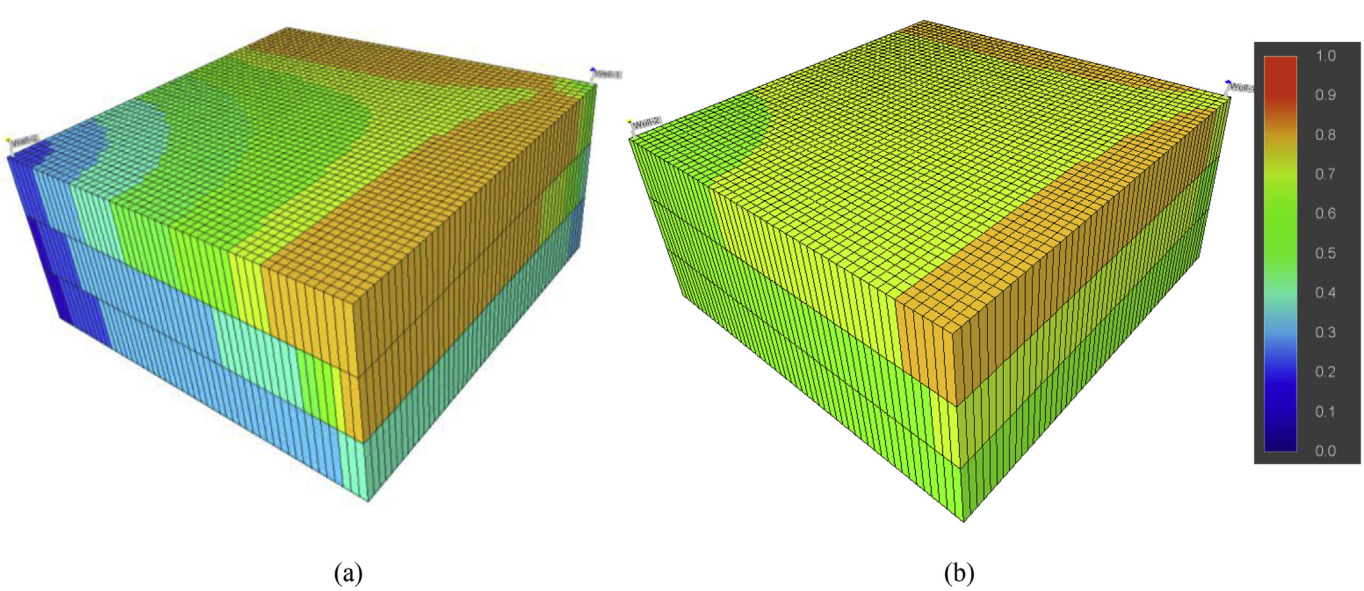



**Fig. 5.** The oil distribution map after 50 years simulation time: a) native b) exposed. Higher residual oil saturation is observed for the exposed case, which reflects the damage incoporated in the relative permeability.

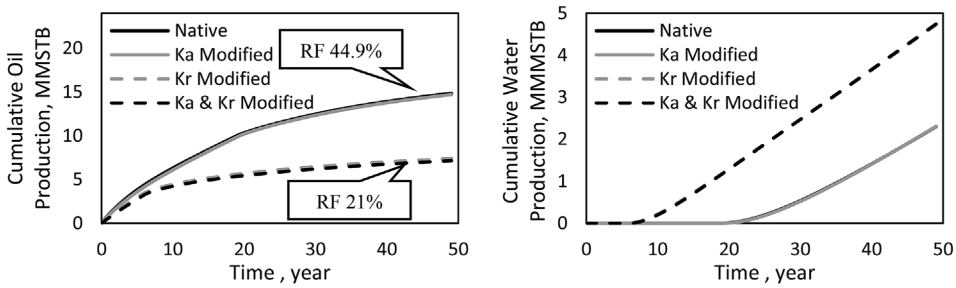



**Fig. 6.** The impact of the asphaltene deposit on reservoir productivity: a) Cumulative oil production b) Cumulative water production. (Native case does not consider the asphaltene deposition, Ka case considers the damage occurred in the absolute permeability only, Kr case considers the damage occurred in the relative permeability only, and Ka & Kr case considers the damage to both the absolute and relative permeability).

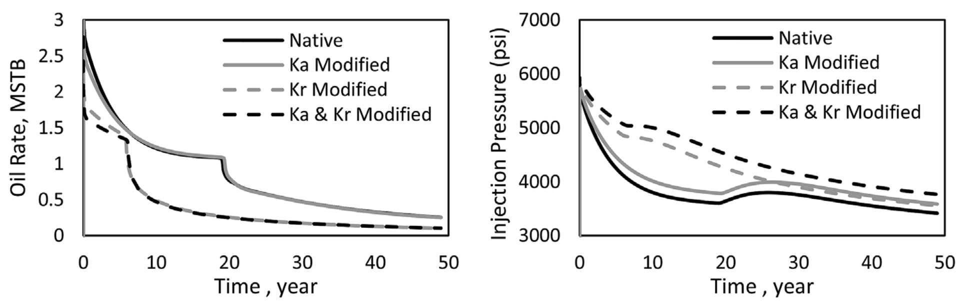



**Fig. 7.** The impact of asphaltene deposit on the reservoir productivity and injectivity: a) the oil rate b) the injection pressure.

reduction and relative permeability effects shows that the effect of changes in relative permeability are much more pronounced than the changes in absolute permeability.

## Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petrol.2018.11.056.

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