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Impact of salinity and temperature variations on relative permeability and residual oil saturation in neutral-wet sandstone

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Abstract:
Low-salinity water flooding has become one of the major emerging enhanced oil recovery techniques where lower salinity water is flooded into a hydrocarbon reservoir in order to increase oil recovery. It's been widely reported that reservoir wettability alteration from oil-wet to water-wet in a low-salinity water process improves oil recovery. Many factors control system wettability, however, role and intensity of each factor is not completely understood. Therefore, several reported affecting factors on wettability alteration were eliminated in the present work in order to determine the impact of different low-salinity water on oil and water relative permeability curves and residual oil saturation. A series of experiments were performed where three simulated brine solutions were injected into oil saturated thoroughly cleaned neutral-wet sandstone core plugs. The effect of injected brine temperature on oil and water relative permeability curves and residual oil saturation was also determined by injecting 115,000 ppm salinity brine at three different temperatures. Results indicate that decreasing flooded water salinity alters the wettability preference of the rock towards favorable water-wetting conditions. Water-wet conditions decrease water mobility and enhance oil mobilization leading to better oil microscopic displacement efficiency and reduced residual oil saturation. Elevated temperature reduces water relative permeability and residual oil saturation.

1. Introduction

Effect of low-salinity water (LSW) flooding on oil recovery has been intensively studied numerically and experimentally (Ben Mahmud et al., 2019, 2020). Experimental findings on clastic cores indicate that LSW leads to an increase in oil recovery (Webb et al., 2004; McGuire et al., 2005; Zhang et al., 2007). LSW experiments began in the late 1960s (Bernard, 1967). Patil et al. (2008) and Tang and Morrow (1997) reported 20% increase in oil recovery factor while Aladasani et al. (2014) reported up to 40% increase in oil recovery factor. Webb et al. (2004) reported that decreasing flooded brine salinity from 80,000 to 1,000 ppm significantly increased oil recovery. The exact mechanisms behind LSW are still subject of intense speculation and assessment. This is because underlying mechanisms causing complex interactions at interfaces of water, oil and rock and their influence on dynamic flow characteristics in porous materials. Effects of wettability alteration, pH, osmosis pressure, multicomponent ion exchange (MIE), fine migration, LSW chemical mechanism, double-layer, surface roughening due to clay swelling and calcite dissolution have all been reported as mechanisms or factors that result in additional oil recovery. For instance, adsorption/desorption of carboxylic material onto clay increases water pH which, in turn, favorably alters rock

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wettability that results in additional oil recovery (Morrow et al., 1998; McGuire et al., 2005; Piñerez et al., 2016). Salinity of injected brine, pH and interaction between polar components that exists in crude oils and reservoir rock are also factors that may directly alter rock wettability (Tang and Morrow, 1997; Buckley et al., 1998). On the contrary, an increase in pH was shown to not directly lead to an increase in oil recovery (Lager et al., 2008a; Rezaeidoust et al., 2009). The increase in oil recovery during LSW is attributed to brine expansion because osmotic pressure increases (Tang and Morrow, 1999; Sandengen and Arntzen, 2013; Sandengen et al., 2016; Fredriksen et al., 2017). Fines migration due to LSW was also attributed to the increase in oil recovery (Bernard, 1967; Tang and Morrow, 1999; Skauge et al., 2008; Hadia et al., 2012). Fines migration mechanism induces water flux diversion leading to improved microscale sweep efficiency and reduced residual oil saturation (Al-Sarihi et al., 2018). On the contrary, fines migration did not contribute towards additional oil recovery (Shaker and Skauge, 2013; Amirian et al., 2017).

MIE was among the factors that led to an increase in oil recovery during LSW (Buckley et al., 1998; Lager et al., 2008b; Seccombe et al., 2008; Rezaeidoust et al., 2009; Mugele et al., 2016). Ligthelm et al. (2009) observed LSW increased the thickness of an ionic double layer separating oil and clay interfaces. Consequently, reduction in electrostatic repulsion force leading to wettability alteration and ultimately an increase in oil recovery. Increasing surface roughness during LSW was also shown to increase oil recovery due to clays swelling that alters favorably the rock wettability (Marhaendrajana et al., 2018). Polar molecules that exist in crude oil are first adsorbed by the rock altering its wettability to partly oil-wet. Additionally, during LSW oil is desorbed from the clay surfaces altering the rock wettability to water-wet from oil-wet (Seccombe et al., 2008). Calcite dissolution mechanism means dissolved particles transfer oil on its surface leading to additional oil recovery (Al-Saedi et al., 2020).

The current understanding is oil recovery by LSW is affected by the reservoir wetting condition (Rivet et al., 2010; Hadia et al., 2012; Shaker and Skauge, 2013; Ben Mahmud et al., 2019, 2020). For instance, altering a reservoir rock from oil to water wettability coincides with increase in oil relative permeability and oil recovery and reduction in residual oil saturation and water relative permeability. This preferable outcome has been shown experimentally to occur during LSW (Webb et al., 2004; Agbalaka, 2006; Rivet et al., 2010; Vledder et al., 2010; Morrow et al., 2011; Fjelde et al., 2012; Kulathu et al., 2013). On the hand and contrary to the current understanding, the ion exchange taking place at clay surface during LSW may in fact shift the wettability state of sandstone formation from water-wet to oil and mixed-wet states leading to a decrease in oil recovery (Sandengen et al., 2011; Fjelde et al., 2012). Strongly water-wet rock systems may only be slightly affected by LSW, as the rock system is already water-wet and cannot become more water-wet than it is (Sorbie and Collins, 2010).

Not many studies are concerned with LSW effect on oil and water relative permeability curves as the focus has mostly been on LSW effect on oil recovery. Experimental results on neutral-wet cores showed that LSW does not lead to an increase in oil recovery because the cores' wetting state is already favorable (Hadia et al., 2011). However, more LSW experimental results on neutral-wet systems suggest that neutral-wet systems are favorable over water-wet systems leading to the highest ultimate oil recovery (Ashraf et al., 2010; Alotaibi et al., 2011; Spildo et al., 2012). Chaabi et al. (2021) recently studied LSW at laboratory scale utilizing non-neutrally wet core plugs then numerically extracted relative permeability curves. In the present study several factors that have been observed to affect oil recovery while manipulating LSW, were isolated. Particular attention was given to events that influence varying LSW on oil recovery and water/oil relative permeability curves in neutral-wet sandstone. Thus, the main objective is to evaluate the definite effect of salinity increase/decrease on oil and water relative permeability curves and residual oil saturation on neutral-wet sandstone systems as previous studies on neutral-wet systems concluded conflicting observations on the residual oil saturation (Ashraf et al., 2010; Alotaibi et al., 2011; Hadia et al., 2011; Spildo et al., 2012). Three brine salinities of 65,000, 115,000 and 165,000 ppm were utilized. Other mechanisms that were reported to take place during LSW and discussed above were excluded. Fines migration role, for instance, was isolated by thoroughly cleaning the core plugs as shown in Samples Preparation and Cleaning section below. Core plugs were initially saturated with oil before LSW was conducted. The core plugs utilized were neutrally wet, therefore, the effect of capillary forces was eliminated, as the rock surface has no preferential wettability. The core plugs were also thoroughly cleaned by solvents to remove any clay and salt so that mechanisms such as fine migration and surface roughening due to clay swelling were eliminated.

Despite the fact that there are conflicting observations about temperature effects on fluids relative permeabilities, most studies conclude that temperature variation affects fluids relative permeability. Reservoir temperature was found to affect LSW as temperature may alter reservoir wettability and therefrom increase or decrease oil recovery (Ben Mahmud et al., 2020). The effect of temperature on LSW in sandstone rock has been studied (Zhang et al., 2007; Agbalaka et al., 2008; Patil et al., 2008; Rivet et al., 2010; Fjelde et al., 2012; Suijkerbuijk et al., 2013; Xie et al., 2017; Ben Mahmud et al., 2019). Temperature increase during LSW was found to favor wettability shift towards water-wet condition by altering water pH from originally acidic to alkaline conditions. Increasing temperature also enhanced ion exchange between brine and clay surface. Among the objectives of the present study is to also study the influence of temperature on oil recovery and oil and water relative permeability curves in neutral-wet sandstone. Brine of 115,000 ppm salinity concentration was injected at temperatures of 77, 105 and 160 °F. Higher temperatures should have been considered to fully determine the effect of elevated temperature, however, due to utilized equipment limitation the highest temperature considered was 160 °F.

Table 1. Dimensions, wettability and porosity of the core plugs.

Core plug	Porosity (%)	I_W	I_O	$I_{A/H}$	Length (cm)	Permeability (mD)
A	11.80	0.111	0.155	-0.044	4.44	2.10
B	13.40	0.099	0.035	0.064	4.41	15.30

2. Experimental setup

2.1 Samples preparation and cleaning

The utilized core plugs were extracted of hydrocarbons using toluene, leached of salt using methanol and oven dried at 176 °F. Silver nitrate solution was used to ensure the removal of salts existing in the pore spaces. The core plugs were subjected to extraction by toluene solvent after previously de-watered by distillation and refluxed in each extraction unit for at least twelve hours to remove any fluids in the core plugs. The core plugs were refluxed for a minimum of 24 hours. Upon removal from extraction apparatus, the core plugs were tested for fluorescence under ultraviolet light to check for hydrocarbon presence. The core plugs were subsequently transferred to a standard oven at 140 °F and dried. Then placed in individual soxhlets and cleaned with methanol to remove salts. The methanol in the soxhlet chamber was tested with silver nitrate solution to ensure that the salt derived from formation water had been removed from the core plugs. Finally the core plugs were returned to the oven and again dried to constant weight and subjected to porosity measurements using Helium Gas Expansion Porosimeter (model number LL285SP, manufacturer ErgoTech-UK). Porosity measurements are based on the principle of Boyle's Law. Permeability was measured by a Nitrogen Gas permeameter (model number 90145, manufacturer COREX Services-UK), taking into account Klinkenberg permeability correction.

2.2 Wettability measurements

Amott method was considered for wettability measurements. Several samples were selected to perform wettability measurements for the purpose of selecting two most neutrally wet core plugs. The test procedure has the following four steps.

1) Initial oil drive: A hydrostatic core holder (model number 3020-081, manufacturer Core Lab-TEXAS-U.S.A) was used to individually measure the wettability of the fully saturated core plugs. An overburden pressure was applied then an injection of refined mineral oil commences at the top of the core plug and produced brine was monitored as an effluent. At constant flow and zero brine production, the irreducible water saturation was obtained.
2) Spontaneous (free) imbibition of brine: The oil saturated core plugs at their irreducible water saturation were then submerged in formation brine within Amott vessels. Volume of imbibed brine was then measured for a month versus time. The core plugs were monitored until the oil/water saturation profile was in equilibrium.
3) Brine drive: On achieving equilibrium, the core plugs were exposed to brine drive. The hydrostatic core holder was again used to hold the core plugs individually at the overburden pressure. An injection of formation brine commenced at the top of the core plug and produced oil was monitored as an effluent. At constant flow and zero oil production, the residual oil saturation was obtained.
4) Spontaneous (free) imbibition of oil: The brine saturated core plugs at their residual oil saturation were then submerged in refined mineral oil within Amott vessels. Volume of imbibed oil was then measured for a month versus time. The core plugs were monitored until the oil/water saturation profile was in equilibrium. The core plugs were monitored until the oil/water saturation profile was in equilibrium.

The following equation is used to calculate the Amott/Harvey ($I_{A/H}$) wettability index from the derived data:

$$I_W = \frac{B_I}{T_{OR}} \tag{1}$$

where I_W is the Amott/Harvey water wettability index; B_I is the imbibed brine; T_{OR} is the recovered total oil.

$$I_O = \frac{O_I}{T_{BR}} \tag{2}$$

where I_O is the Amott/Harvey oil wettability index; O_I is the imbibed oil; T_{BR} is the recovered total oil.

$$I_{A/H} = I_W - I_O \tag{3}$$

The $I_{A/H}$ relative displacement index combines these indices: 1 for complete water-wet, -1 for complete oil wet and neutral-wet when $-0.3 < I_{A/H} < 0.3$.

Two most neutral core plugs were selected for the present study, with their $I_{A/H}$ being -0.044 and $+0.064$ as shown in Table 1. Due to facilities' availability and time constraints, it was possible to conduct Special Core Analysis flow experiments at different salinities and temperatures for only two core plugs.

Several core plugs were tested for wettability preference but excluded because their wettability states were not as close to neural wettability as the two selected core plugs shown in Table 1.

2.3 Relative permeability measurements

Before conducting relative permeability measurements, the clean and dry core plugs were subjected to different analysis to determine porosity and permeability as indicated above. Benchtop Liquid Permeability System was used for performing flow tests on the core plugs. In each experiment, the core plug was loaded in a stainless steel saturator and evacuated for at least 24 hours. Simulated brine containing sodium chloride and having viscosity of 1.12 centipoises and density of 1.08

gm/cc was introduced at constant flow rate of 1 cc/min. The brine was injected at the desired salinity and temperature followed by pressurization to 2,500 psig to assist penetration. Typically, LSW refers to cases where salinity is below 10,000 ppm; however, salinities of 65,000, 115,000 and 165,000 ppm were considered. Sandstone formation salinity from which the core plugs were extracted is 220,000 ppm. Therefore, 65,000, 115,000 and 165,000 ppm salinities were selected and utilized to investigate the potential benefits of flooding brine at lower salinities into the formation from which the core plugs were extracted. Complete saturation was secured by gravimetric checks. The saturated core plugs were confined at 2,500 psig net-overburden pressure in the hydrostatic core holder. Refined mineral oil having density of 0.76 gm/cc and viscosity of 1.87 centipoises at 77 °F temperature was then flooded into each core plug from the top. Water production was monitored as it exits the effluent of the core plug. Oil permeability was measured at constant flow and the effluent was brine free. On completion of oil permeability measurements, the core plug was situated in the hydrostatic core holder under overburden pressure. The same brine was flooded at the required temperature and constant flow rate at the top of the core plug utilizing high performance liquid chromatography pump. Differential and confining pressures, produced volumes and time were all recorded. At water cut of 99.98%, brine injection was terminated. Water permeability was measured as oil production ended and the experiment was completed. Jones and Roszelle (1978) calculation principle technique was built in Sendra® Software (Sendra, 2013) and utilized to calculate relative permeability using obtained total volume, oil volume and time. Sendra, which is one-dimensional two-phase black-oil software, was utilized to analyze and plot relative permeability experiments. Data measured from experiments are inserted into the software to construct water-oil relative permeability curves that are always smooth because of the technique employed by the software. The software employs water flooding technique in which oil relative permeability at irreducible water saturations was used to normalize water relative permeability curves. The software is a coreflood simulator with a fully implicit two-phase core flow simulator designed to simulate and verify Special Core Analysis experiments. It can be used for both imbibition and drainage processes, for oil-water, gas-oil or gas-water experiments. Sendra utilizes two relative permeability data sets; the initial wettability and the final wetting established at the end of smart water injection. Furthermore Sendra contains a graphical tool used to plot results and compare a variety of flow properties.

The following equation was used to calculate residual oil saturation S_{or}:

$$S_{or} = \frac{V_p - S_{wi}V_p + V_o}{V_p} \tag{4}$$

where V_p is the core plug pore volume, S_{wi} is water saturation remaining inside the core plug and V_o is the total oil volume out of core.

The cleaning process described above is then repeated for the upcoming salinity concentration and temperature for each core plug.

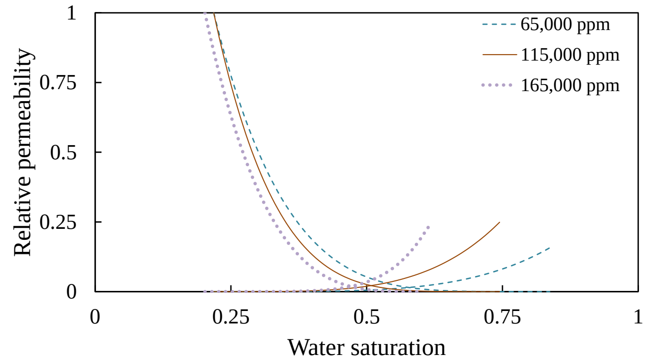

Fig. 1. Relative permeability curves of oil and water for core plug A at flooded water salinities of 65,000, 115,000 and 165,000 ppm.

3. Results and discussion

3.1 Effect of salinity variation

To relate the interfacial behaviors to oil and water dynamic flow in reservoir rocks, relative permeability curves using core flooding tests were established. Representative reservoir water salinities of 65,000, 115,000 and 165,000 ppm were utilized. Fig. 1 shows relative permeability curves of oil and water as a function of water saturation for core plug A at 77 °F temperature. Residual oil saturations obtained were 15.92%, 24.88% and 31.79%, respectively. Decrease in flooded brine salinity has opposite effect on water and oil relative permeability curves. Oil relative permeability increases at a given saturation and water relative permeability decreases at a given saturation. Thus, Fig. 1 shows that a decrease in brine salinity can reduce water relative permeability and improve oil relative permeability due to wettability alteration from neutral-wet to water-wet conditions. Concurrently, an increase in brine salinity leads to less favorite wetting condition which causes breakup to oil phase continuity, rapid decrease in oil relative permeability and oil trapping. As flooded brine salinity drops, the core plug wettability shifts to water-wet conditions. The shift is likely due to change in contact angle and MIE (Lager et al., 2008b). MIE releases organic compounds, positively and negatively charged, during LSW. Moreover, LSW may enhance double-layer expansion releasing from the rock surface oil-bearing divalent ions (Yousef et al., 2011). Wetting alteration in neutral-wet pores to preferentially water-wet condition by LSW can also be influenced by surface chemistry mechanisms such as cation exchange. Fig. 1 implies that the 65,000 ppm salinity brine lowered the Interfacial Tension (IFT) between oil and injected brine more than the 115,000 ppm salinity brine. This leads to more favorite water wetting condition than the neutral wetting conditions. Higher capillary number is achieved and improved oil recovery. Brine with lowest salinity also generates the highest interfacial viscoelasticity at water oil interface that prevents or slows the breakage of oil ganglia (Wei et al., 2018). Clay dispersion, which is usually induced by low-salinity brine, is not a contributing factor towards wettability shift because, as previously indicated, the core plugs were thoroughly cleaned and dried before conducting the experiments. Fig. 1 shows low water effective permeability and therefore more tendency towards water-wet as flooded brine salinity decreases. Overall, as the core plugs are neutral-wet, no capillary pressure exists on the intermediate-wet surface strata, and the seepage of oil and water phases in the pores are free from the influence of capillary forces. Thus, snap-off displacement mechanism is suppressed and frontal invasion of pores and connecting throats displacement takes place (Mahmud, 2017). The flooded brine evenly displaces oil from small and large pores and throats maintaining interconnected oil blobs leading to high oil mobility and sweep efficiency. This, in turn, results in rapid reconnection and oil coalescence of large oil clusters and an increase in oil relative permeability. Moreover, different sizes of pores and throats of neutral wettability core plugs lead to oil columns of different sizes being present in stationary state. Wettability hysteresis still takes place during waterflooding, however, Jamin effect is less than the case for strong oil-wet or strong water-wet core plugs. Therefore, macroscopic displacement efficiency and sweep efficiency of water are promoted resulting in improved oil recovery.

As the saturation of flooded water increases and oil is produced, the number of oil filled pores decreases leading to decreasing oil relative permeability. At the end of waterflooding, the remaining oil is completely trapped and oil relative permeability drops to zero. The equal-permeability point or the crossover point between water and oil relative permeability curves shifts to the right as LSW altered the wetting condition of the core plug from neutral-wet to weak water-wet state. The shift in relative permeability curves is proportional to low-salinity brine. Recent studies by Ben Mahmud et al. (2020) and Li and Hou (2019) and another study by Sufi et al. (1982) concluded decreasing injected brine salinity shifts wettability from originally oil-wet to completely water-wet. From Fig. 1, the end-point water relative permeability slightly decreased from 25.00% by the end of higher salinity injected brine of 165,000 ppm to 24.89% and 14.35% by the end of lower salinity injected brines of 115,000 and 65,000 ppm, respectively. Identical end-point water relative permeability observations have been reported by Shehata et al. (2016).

Fig. 2 shows relative permeability curves of oil and water for core plug B that was also flooded by brines of 65,000, 115,000 and 165,000 ppm salinities at 77 °F temperature. LSW clearly shifted the relative permeability curves. Water relative permeability decreased and oil relative permeability increased. Consistent trend has recently been noted by Chaabi et al. (2021). A shift in residual oil saturation by LSW as residual oil saturations were 8.75%, 11.11% and 14.05% after the core plug was flooded by brines with salinities of 65,000, 115,000 and 16,500 ppm, respectively. Oil relative permeability was higher as the core plug was flooded by water salinity of 65,000 ppm than oil relative permeability when brine salinity of 115,000 ppm was flooded into the core plug. Water relative permeability, on the contrary, was lower as the core plug was flooded by brine salinity of 65,000 ppm than water relative permeability as 115,000 ppm brine salinity was flooded into the core plug. The shift in wettability, from neutral-wet to water wet, is more evident in core plug B, Fig. 2, than core

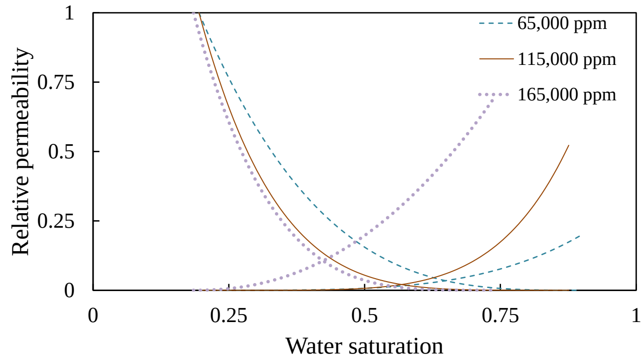

Fig. 2. Relative permeability curves of oil and water for core plug B at flooded water salinities of 65,000, 115,000 and 165,000 ppm.

plug A, Fig. 1. This indicates the complex geometry of the throats and pores systems in sandstone (Mahmud, 2022). The effect salinity variation on altering wettability characteristics of the core plugs and lowering the oil-water IFT is evident from Figs. 1 and 2. During the present injection experiments into the core plugs of various salinity brines, no evidence of reactions between flooded brine and minerals native to the core plugs. Although the interfacial tension was not measured, low salinity brine is known to reduce IFT between water and oil that in turn alters the rock's wettability from neutral to preferentially water-wet. From Fig. 2, water relative permeability end-point decreased from 65.61% by the end of higher salinity injected brine of 165,000 ppm to 52.24% and 19.49% by the end of lower salinity injected brines of 115,000 and 65,000 ppm, respectively.

3.2 Effect of temperature variation

Figs. 3 and 4 show relative permeability curves of oil and water as a function of water saturation of core plugs A and B after being waterflooded by 115,000 ppm brine salinity at temperatures of 77, 105 and 160 °F. From Figs. 3 and 4, water relative permeability decreases with increasing temperature at a given saturation. However, temperature increase has little effect on oil relative permeability at a given saturation. Table 2 shows how temperature increase has clearly decreased residual oil saturation for core plug A and slightly decreased the residual oil saturation for core plug B. This observation is partly consistent with those of Sufi et al. (1982) who reported temperature effect, at similar temperature range to the present study, on oil and water relative permeability curves and residual oil saturation in unconsolidated clean sand. Their findings suggest temperature variation did not affect water and oil relative permeability curves, however, residual oil saturation decreased as temperature increased. From Fig. 3, as temperature increases from 77 to 160 °F, oil relative permeability remains somewhat unchanged and water relative permeability decreased. Residual oil saturation also decreased from 24.88% at 77 °F to 18.50% at 160 °F as shown in Table 2. From Fig. 4, oil relative permeability also remained somewhat unchanged and water relative permeability decreased at a given saturation. From Table 2, as temperature increased from 77 to 160 °F, residual oil saturation decreased from 11.11% to

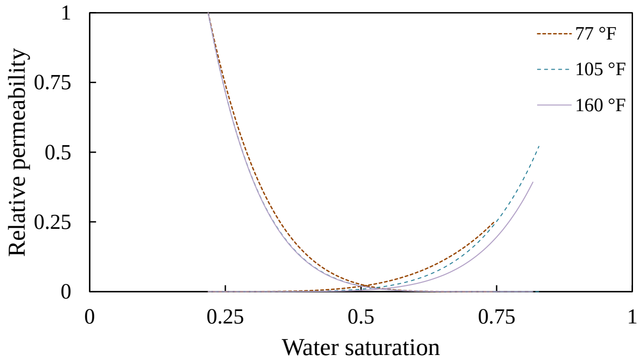

Fig. 3. Oil and water relative permeability curves of core plugs A at flooded water salinity of 115,000 ppm and temperatures of 77, 105 and 160 °F.

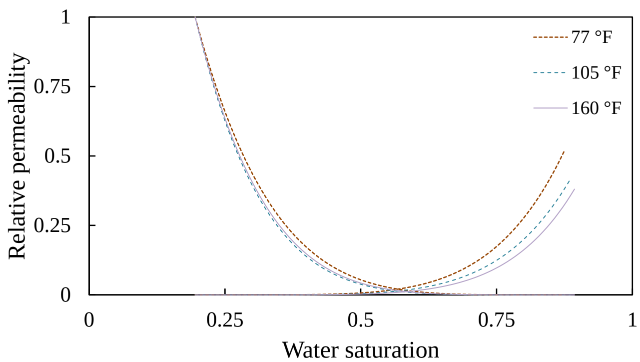

Fig. 4. Oil and water relative permeability curves of core plugs B at flooded water salinity of 115,000 ppm and temperatures of 77, 105 and 160 °F.

Table 2. Residual oil saturation of core plugs at different temperatures.

Core plug	S_{or} (%)		
	77 (°F)	105 (°F)	160 (°F)
A	24.88	17.20	18.50
B	11.11	10.01	9.21

9.21%, respectively.

In Figs. 3 and 4, the equal-permeability point slightly shifts to higher water saturation as temperature increases indicating limited shift in wettability towards water-wet. In general, it can be deduced that an increase in temperature makes oil flow faster than water. This indicates that temperature increase in sandstone increases its water wetness. Temperature increase reduces oil viscosity and increases flow mobility and capability of oil leading to reduction in residual oil saturation. Liang et al. (2021) reported similar observations in a recent experiential study. It is possible to experimentally conclude that elevated temperature only minimally affect oil relative permeability. However, notable reduction was observed in residual oil saturation for neutral-wet sandstone within the temperature range of the present study. The neutral-wettability status of both core plugs was altered towards water-wet as flooded brine temperature increased. Water relative permeability curves deviated to the right as temperature increased. Factors affecting water and oil relative permeability curves as temperature increases include molecules adsorption and desorption, thermal expansion of fluid and rock particles and oil viscosity alteration. As the highest temperature applied in the present study is 160 °F, triggering molecules adsorption and desorption and thermal expansion of fluid and rock particles were probably unachievable. As mentioned above, higher temperatures should have been considered but equipment utilized for the experiments could only tolerate temperature up to 160 °F. However, it can be confirmed that as temperature elevated from 77 to 160 °F, residual oil saturation decreased by up to 25.64%. Decrease in residual oil saturation is a result to the decreased in oil viscosity as the temperature of flooded brine increased from 77 to 160 °F. This, in turn, improved oil mobility and overall sweep efficiency. Temperature displacement also affects interfacial energies between fluids and solid interfaces, thus, contact angle change and wettability alteration towards water-wetness. Relative permeability curves deviate to the right as temperature increases and relative permeability to water decreases apparently and relative permeability to oil increases. The equal-permeability point shifts to the right with temperature. Figs. 1-4 confirm that wetting parameters obtained at the core-scale affects saturation functions and relative permeability and other flow properties (Zou and Sun, 2020).

4. Conclusions

Several laboratory experiments were performed to study the impact of LSW and temperature on oil and water relative permeability curves and residual oil saturation in neutral-wet sandstone. Brine concentrations of 65,000, 115,000 and 165,000 ppm were utilized and temperatures ranging from 77 to 160 °F were applied. Several factors that have previously been reported to be affected by LSW, such as fine migration and surface roughening due to clay swelling, were eliminated. The following observations and conclusions are made:

- Relative permeability curves of both oil and water shift to the right with decreasing flooded water salinity because rock wettability shifts towards water-wet condition.
- As salinity decreases, water relative permeability decreases and oil relative permeability increases, however, the increase ratio of oil is less than that of water. Moreover, equal-permeability point deviates to the right. Overall oil and water relative permeability curves also deviate to the right as salinity decreases.
- Flow mobility of oil improves and residual oil saturation decreases as flooded brine salinity decreases.
- Injecting brine with lower salinity alters the wettability conditions of sandstone from neutral to water-wet which is more favorite for higher oil relative permeability, reduced residual oil saturation and higher ultimate oil recovery than neutral-wet.
- Temperature elevation leads to decrease in residual oil saturation because oil mobility improves and water rel-

ative permeability decreases. Moreover, as temperature increases, oil viscosity decreases and the mobility ratio of water to oil decreases.
- Equal-permeability point and oil and water relative permeability curves shift to the right as temperature increases indicating shift in wettability from neutral to water-wet.

Conflict of interest

The author declares no competing interest.

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