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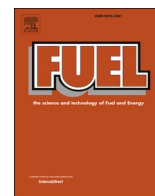
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# Experimental study of electrical heating to enhance oil production from oil-wet carbonate reservoirs

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## ABSTRACT

New approaches for enhanced oil recovery (EOR) with a reduced environmental footprint are required to improve recovery from mature oil fields, and when combined with carbon capture and storage (CCS) can provide useful options for resource maximisation during the net zero transition. Electrical heating is investigated as a potential EOR method in carbonate reservoirs. Samples were placed in an apparatus surrounded by a wire coil across which different DC (direct current) voltages were applied. Monitoring the imbibition of both deionized water (DW) and seawater (SW) into initially oil-wet Austin chalk showed that water imbibed into the rock faster when heated in the presence of a magnetic field. This was associated with a reduction in the water–air contact angle over time measured on the external surface of the sample. Without heating, the contact angle reduced from 127° approaching water-wet conditions, 90°, in 52 min, while in the presence of heating with 3 V, 6 V, and 9 V applied across a sample 17 mm in length, the time required to reach the same contact angle was only 47, 38 and 26 min, respectively, while a further reduction in contact angle was witnessed with SW. The ultimate recovery factor (RF) for an initially oil-wet sample imbibed by DW was 13% while by seawater (SW) the recorded RF was 26% in the presence of an electrical heating compared with 2.8% for DW and 11% for SW without heating. We propose heating as an effective way to improve oil recovery, enhancing capillary-driven natural water influx, and observe that renewable-powered heating for EOR with CCS may be one option to improve recovery from mature oil fields with low environmental footprint.

## 1. Introduction

While fossil fuel production needs to decrease rapidly to achieve net-zero emissions by 2050, the application of large-scale carbon capture and storage (CCS) implies that conventional fuels such as oil still have a key role to play during the energy transition [1,2]. However, diminishing resources, increasing extraction costs, and environmental concerns require the maximization of yield from existing infrastructure and resources. In this context, total production from carbonate reservoirs during primary and secondary recovery only accounts for about 30% of existing reserves [3,4], which means that a significant amount of oil remains unrecovered due to unfavorable wettability, fractures and low permeability. Conventional techniques are incapable of producing 60–70% of the oil in place as seen in some sandstone fields [5].

Furthermore, conventional techniques (thermal and chemical injection: polymers, surfactants and alkaline) are not environmentally friendly in terms of chemicals used, CO<sub>2</sub> emissions, high water usage, and high energy consumption [6,7]. Considering this, new approaches for enhanced oil recovery (EOR) with a reduced environmental footprint are required to improve recovery from mature oil fields. Such techniques typically use magnets, electricity (Electrical EOR, EEOR), and CO<sub>2</sub>, and can significantly enhance oil yield from existing reserves [8]. These techniques are potentially game-changing if more laboratory and field research are considered during the energy transition because they allow energy saving, less water usage, and less capital expenditure by reducing the use of chemicals. If the energy used comes from renewable sources, this further reduces the environmental footprint.

The focus of this work is on EEOR, which has been considered as an

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alternative technique to conventional EOR [9]. Electrical heating, EH, of heavy oil reservoirs has been used effectively in near wellbore areas. When used in suitable reservoirs, downhole resistive, dielectric, or induction electric heating systems can be used to stimulate wells. EH can be especially useful in cases where steam cannot be utilized owing to depth, formation incompatibility, poor incipient injectivity, significant heat losses, or the presence of thief zones [10]. Several EOR techniques exist, including microwave heating, direct current (DC) heating, low frequency heating, microwave heating, and induction heating [7]. Microwave heating (MH) is classified as a non-aqueous technique. It is a substitute for hydraulic fracturing, which has numerous environmental and geological constraints [11]. MH employs electromagnetic waves with frequencies ranging from 300 MHz to 300 GHz and wavelengths ranging from 1 mm to 1 m [12]. Furthermore, increasing the intensity of microwave radiation increases average production even more [13]. However, the high cost of initial equipment setup and the uncertainty associated with the quantification of MH at high temperatures limit its commercial application [14]. Electromagnetic (EM) induction heating is used in reservoirs with low water saturation [7]. It is most effective in shallow wells, does not require a large amount of water, and can be used in fractured reservoirs with high permeability. However, there are several drawbacks. For example, corrosion of the equipment can pose a problem, particularly at high salt concentrations [8]. In DC heating, electricity is passed between cathodes (negative electrodes) in the producing reservoir and anodes (positive electrodes) at the surface and/or at depth [15]; again, corrosion is a potential problem.

Compared with steam flooding, EEOR, in its different forms, appears to be superior in terms of depth and heat loss control, and better results can be achieved in heterogeneous formations [16]. Also, the electricity supplied to the reservoir can increase oil temperature and create vibrations within hydrocarbon molecules [7]. EH has the benefit of reducing the oil viscosity, hence it is implemented in heavy oil reservoirs: it is a more efficient thermal recovery technique than steam flooding with less heat loss [8,17,18]. Up to 92% of the electric energy is transferred to the hydrocarbon reservoir. Furthermore, it reduces oil viscosity in regions that are not accessible by steam injection, and it ensures a uniform reservoir temperature during thermal EOR injection [19]. In the Rio Panan field in Brazil, a low frequency EH field trial was conducted. After 70 days of heating, there was an increase in oil production from 1.2 bbl./day to 10 bbl./day [10,20].

In addition to a reduction in viscosity, the electric field produced can change the rock wettability, known as electrowetting [21]. Electrowetting is commonly used to control small droplets in micro- or nano-fluidic applications [22]. However, only limited laboratory experiments have been conducted to investigate the effectiveness of this EH technique on oil production [8]. EM heating at different frequencies of 5 MHz, 10 MHz, and 20 MHz in the laboratory, caused an increase in oil recovery from 20% to 29%, 32%, and 37%, respectively [23].

The importance the effect of EH on recovery has previously been established [9,15,24]. However, to date, this has not been applied to improve oil mobility as an EOR method in carbonate reservoirs. In addition, no clear laboratory methodology for this process has been proposed until now. Therefore, in this work, an innovative technique was proposed in which a magnetic field was generated inside a rock sample in addition to heating. This was achieved by applying different voltages of 3 V, 6 V, 10 V, 15 V, and 30 V in a circular resistive circuit surrounding a carbonate sample, during spontaneous water imbibition. Furthermore, the effect of EH on contact angle was investigated for deionized water (DW, resistivity of 20 M $\Omega$ ) and seawater (SW, 28000 ppm, 0.2 M $\Omega$ ). In our experiments a DC current was applied around the sample, which in turn resulted in the establishment of a weak magnetic field.

We report encouraging results which suggest that EEOR – if used in conjunction with renewable power sources for heating, and CCS – is a promising environmentally friendly technique for improving oil production from existing reserves.

## 2. Materials and methods

### 2.1. Materials

Table 1 displays the synthetic seawater (SW) formulation.

### 2.2. Methods

#### 2.2.1. Core preparation

Outcrop Austin chalk core plugs of diameter 25 mm were provided by Kocurek Industries, Texas, USA for use in this work. The samples were cleaned by immersion in toluene (supplied by Fisher Chemicals) for 48 h to avoid any presence of impurities which can affect the measurements, while avoiding calcium carbonate precipitation and blocking of pores. Then, the samples were dried for 24 h using a vacuum desiccator (70 °C) [25,26]. After the cleaning and drying stage, the dry mass, and three measurements of diameter and length were taken and averaged. The samples were placed in a vacuum saturator using DW to remove air, and a pressure of  $3.44 \times 10^6$  Pa was applied to push DW inside the core plugs and saturate them with 100% DW. After releasing the pressure, the cores were left in a saturator for 8 to 10 hours. The wet mass was measured, and the samples were placed in the core holder. The porosity of all samples was calculated from dry and wet mass, water density and bulk sample volume. Absolute permeability to water ( $k_w$ ) was calculated using Darcy's law applied to different flow rates (1.5, 2, and 2.5 cm<sup>3</sup>/min) under  $3.44 \times 10^6$  Pa confining pressure. Five pore volumes of model oil – 0.01 mol stearic acid mixed in n-decane (density = 0.730 kg/m<sup>3</sup> at 20 °C, and viscosity 0.69 mPa.s at 40 °C provided by Alfa Aesar and Merck) – were injected into sample to establish a low initial water saturation ( $S_{wi}$ ). The concentration of 0.01 mol of stearic acid, a surface active compound, was selected based on previously published studies [27,28] to make carbonate rocks oil-wet. Core plugs were put inside an ageing cell containing the model oil for 30 days at 40 °C (a temperature of 40 °C was sufficiently high to enable the stearic acid to adsorb on the surface thus altering it from hydrophilic to hydrophobic). 30 days ageing time is required to make the surface oil-wet [29]. Table 2 displays the physical properties of the cores used in this study.

#### 2.2.2. Spontaneous imbibition (SI), and surface tension measurements

A direct current was induced by voltages of up to 30 V applied around an Amott cell by an electrically conductive coil comprising 2160 turns of 0.8 mm wire (supplied by RS PRO UK) 625 m long together with a 50 W heat sink resistor that was placed around a metal cup 10 mm larger in diameter than the Amott cell (see Fig. S1). This created a magnetic field within the sample; furthermore, the current flow through the resistor generated heat, which warmed the apparatus, rock and fluids. Temperature was recorded during spontaneous imbibition into the initially oil-wet samples using a K-type thermocouple (supplied by RS components, UK, and accuracy of  $\pm 0.1$  °C). The magnetic field was calculated for each voltage and presented in Table 3: the values are in the mT range. We hypothesize that heating, rather than the magnetic field, is principally responsible for the changes in contact angle, surface tensions and oil recovery observed in these experiments. Surface tensions (between air and water) of the solutions used was measured with a tensiometer K9 Kruss GMBH and Hanna probe respectively.

Fig. 1 illustrates the workflow used for the experiments.

#### 2.2.3. Contact angle measurements

Two types of measurement of the contact angle between water and air (measured through the water phase) were performed as described below.

##### a) Presence of electricity (using discs) without spontaneous imbibition

Measurements were performed with chalk discs (cut from the aged core) approximately 17 mm in length using diamond saw equipment

**Table 1**

The composition of the seawater, SW, used in this study.

Salts	Sodium Chloride (NaCl)	Sodium Sulphate (Na <sub>2</sub> SO <sub>4</sub> )	Potassium Chloride (KCl)	Sodium Bicarbonate (NaHCO <sub>3</sub> )	Magnesium Chloride (MgCl <sub>2</sub> ·6H <sub>2</sub> O)	Calcium Chloride (CaCl <sub>2</sub> ·2H <sub>2</sub> O)
Mass (g/L)	23.926	4.008	0.677	0.196	10.831	1.5199

**Table 2**

Core properties.

Cores	Diameter (mm)	Length <i>l</i> (mm)	Dry mass (g)	Pore volume (ml)	Porosity $\phi$ (%)	Absolute Perm water $k_w$ (md)	$S_{wi}$ (%)
Core #1 DW WW + EH	24.61	69.73	62.20	9.83	29.69	15.00	27.77
Core #2 SW WW + EH	24.69	69.96	62.58	9.77	29.14	15.36	35.52
Core #3 DW OW + EH	24.98	69.79	65.07	9.00	26.26	15.00	18.89
Core #4 SW OW + EH	24.93	69.88	63.10	9.70	28.43	13.73	26.00

**Table 3**

Estimated magnetic field strengths generated by different voltages during the spontaneous imbibition tests.

Voltage (V)	Current (A)	Magnetic field strength (mT)
3	0.073	2.0
6	0.15	4.0
10	0.24	6.7
15	0.37	10
30	0.74	20

where DW was used as a lubricant and cooling fluid to avoid any ion exchange with the oil-wet chalk surface. The sample was then rinsed with DW before it was dried. Similar to the Amott cell setup, the contact angle measurement device was modified in order to introduce a DC current into the system. A design of 570 turns of 0.45 mm electric wire (supplied by RS PRO UK; 9 V maximum applicable voltage) 90 m long was placed around a small metal cup slightly larger in diameter than the sample diameter of 25 mm to assess the effect of EH on contact angle (see Fig. S2); details of the generated current and estimated magnetic fields are given in Table 4: again these are in the mT range. The sample

was placed (in an inclined position) inside the Amott cell to allow imbibition (DW/SW) with/without the effect of EH. The cup prevented evaporation during the experiments. Two tests were performed twice for each voltage: the first, when the electrical field was switched on at the start of the test, and the second, once the power had been on for an hour before the start of the test (the cup was left empty to avoid evaporation of small water droplets). The temperature was estimated from the specific heat capacity and energy input, which varied according to the sample exposure time. This was the maximum possible temperature of the sample ignoring any heat losses.

During the first set of experiments, different discs of the sample were exposed to different voltages and each voltage (0 V, 3 V, 6 V, and 9 V)

**Table 4**

Estimated magnetic field strength generated by different voltages during the contact angle measurements.

Voltage (V)	Current (A)	Magnetic field strength (mT)
3	0.19	3.6
6	0.38	7.1
9	0.56	11

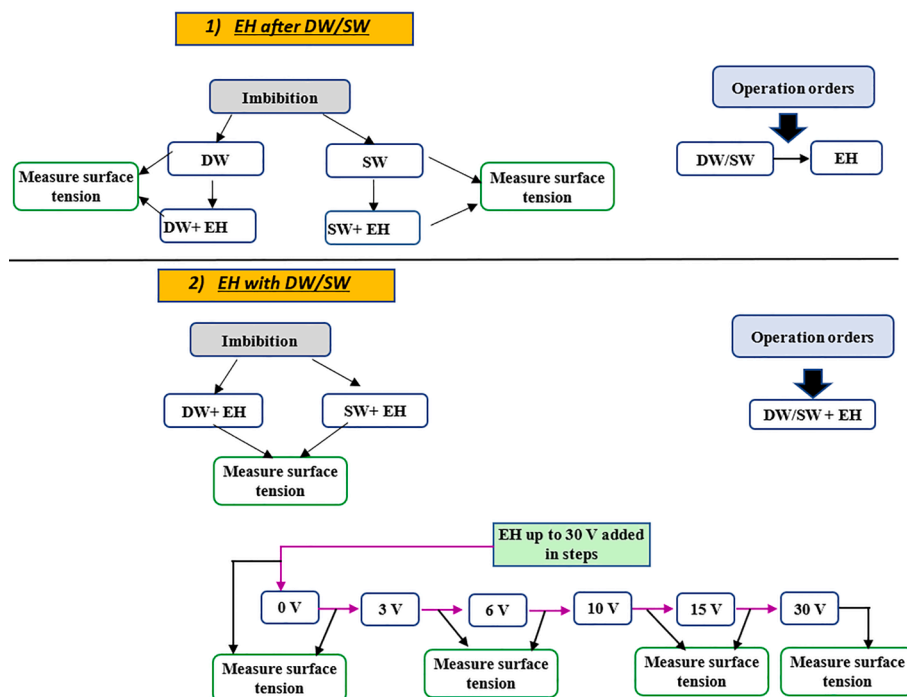


Fig. 1. A flow chart showing the overall experimental workflow.

were assessed for a maximum of 1 h; the test stopped when the contact angle stabilized. At the end of the tests the power was switched off allowing the system to cool to room temperature over 24 h. For the second set of measurements, electrical power was applied to the metallic test cup for 1 h, while the chalk sample was outside it, and then the test was started by placing the sample into the cup and decanting a droplet of the aqueous solution of interest onto the chalk surface. The voltage did not exceed 9 V, for safety. All the tests were repeated.

Fig. 2 presents the workflow used to measure contact angle.

**b) Absence of electricity (using pellets) at the end of spontaneous imbibition**

Pellets (diameter 13 mm) were prepared after drying the cores at the end of spontaneous imbibition (see Fig. S3): the cores were crushed and sieved into powder, which was compressed to cylindrical pellets by applying a force of 90 kN [25,26]. Therefore, the porosities of the pellets were different from the ones given in Table 2 and were evaluated from SEM images using commercial image analysis software, Dewinter Material Plus. The contact angle was then measured (using a DSA 100 goniometer), without introducing electricity.

The contact angle measurement is required because it is done at the end of spontaneous imbibition, where oil recovery and surface tension were assessed under a voltage of up to 30 V. This assesses the direct

effect of EH on the contact angle of an initially oil-wet sample.

**3. Results and discussion**

The effect of EH was first investigated in terms of the contact angle of the aged sample without imbibition. Then, the impact was assessed based on oil recovery, and surface tension (during spontaneous imbibition using DW and SW as displacing fluids). Finally, the impact was assessed on the contact angle of the samples at the end of spontaneous imbibition.

**3.1. Impact of EH on contact angle**

**3.1.1. Contact angle as a function of time**

The average initial value of the measured contact angle on oil-wet chalk was  $126^\circ \pm 1^\circ$ . Contact angles were measured as a function of time in the presence and absence of a DC current (up to 9 V); details of the generated current and magnetic field are given in Table 4. The effect of EH on contact angle was assessed on DW and SW droplets to evaluate the impact of heat generation over time. The results for DW and SW water droplets are given in Table 5, Fig. 3, and Fig. 4.

The displacement of a non-wetting phase (oil in this case) by a wetting phase (water) without the application of pressure is known as spontaneous imbibition. Wettability is the tendency of a liquid to spread

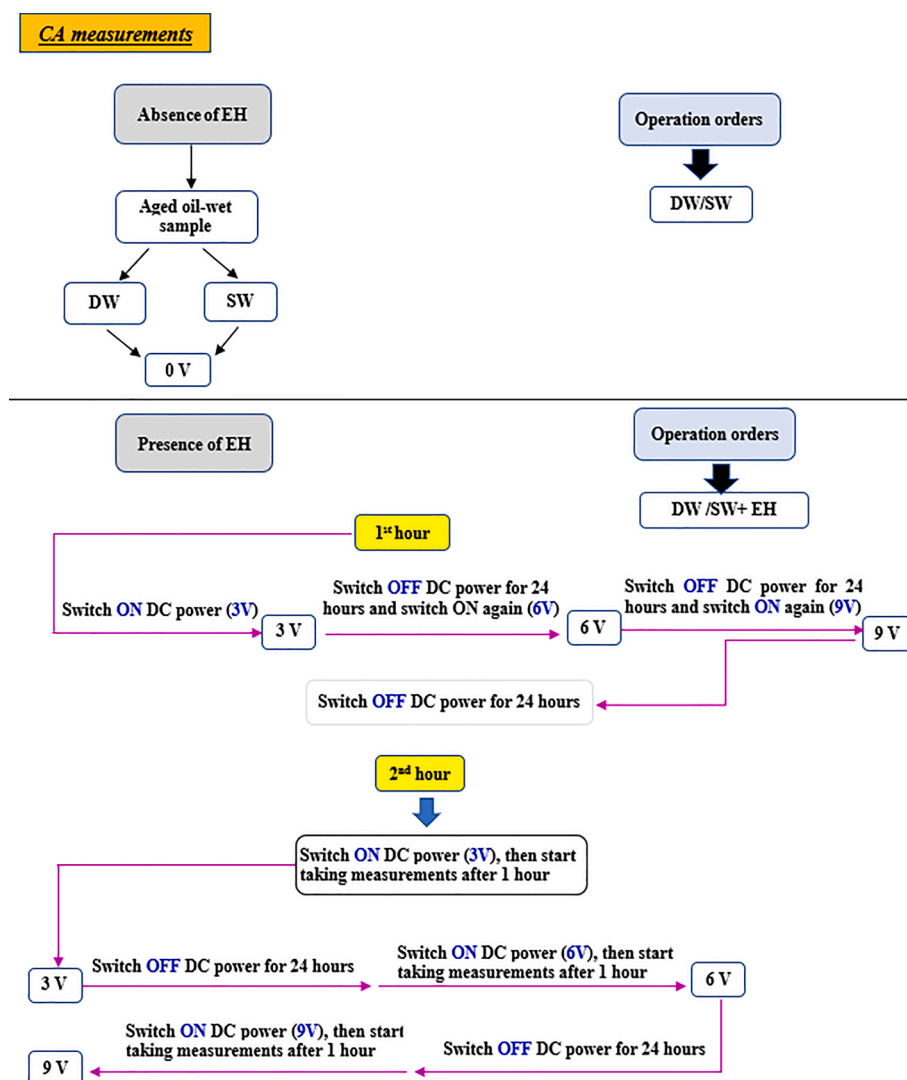


Fig. 2. Contact angle measurements flow chart.

**Table 5**  
Impact of time and voltage on contact angles (on oil-wet chalk).

DW droplet			
First set of measurements taking up to 1 h			
Voltage (V)	Time (min)	Contact angle (°)	Estimated cup temperature <i>T</i> (°C)
0 V	0	127.1	20
	36	110.2	20
	52.4	90.3	20
3 V	0	131.5	20
	33	110.0	24
	47	90.4	26
6 V	0	128.8	20
	30	110.2	35
	38	90.5	40
9 V	0	129.2	20
	20.2	110	43
	26	90.8	50
Second set of experiments where the DC current was maintained in the coil for 1 h initially			
Voltage (V)	Time (min)	Contact angle (°)	Estimated cup temperature <i>T</i> (°C)
3 V	0	126.7	28
	22	110.3	31
	38	90.2	33
6 V	0	124.9	51
	14	110.2	58
	22	90.1	62
9 V	0	127.9	90
	11	110.7	102
	17	90.1	109
SW droplet			
First set of experiments taking up to one hour			
Voltage (V)	Time (min)	Contact angle (°)	Estimated cup temperature <i>T</i> (°C)
0 V	0	129.9	20
	29.4	110.3	20
	40.3	90.0	20
3 V	0	125.5	20
	24.44	110.1	23
	37	90.4	25
6 V	0	129.2	20
	20.2	109.9	30
	26.14	90.8	33
9 V	0	120	20
	2.81	110.5	23
	7.65	90.3	29
Second set of experiments where the DC current was maintained in the coil for 1 h initially			
Voltage (V)	Time (min)	Contact angle (°)	Estimated cup temperature <i>T</i> (°C)
3 V	0	129.0	28
	20.1	110.7	30
	31.91	90.6	32
6 V	0	123.9	32
	10.19	110.0	56

**Table 5 (continued)**

DW droplet			
First set of measurements taking up to 1 h			
Voltage (V)	Time (min)	Contact angle (°)	Estimated cup temperature <i>T</i> (°C)
	17.57	90.7	60
9 V	0	123.8	60
	2.65	110.2	93
	5.51	90.3	96

on a solid surface in the presence of another immiscible fluid. In enhanced oil recovery, wettability determines the interactions between the solid (rock) and the liquids in the reservoir (crude oil, brine). When the contact angle of water droplet is lowered, it indicates a wettability alteration to less oil-wet conditions, which implies that spontaneous imbibition may occur in the system of interest where the water becomes wetting in the presence of oil.

Clearly, water imbibition was faster when EH was applied, as can be seen from comparing Table 5, Fig. 3 (a), Fig. 3 (b), and Fig. 3 (c). For instance, the contact angle declined from  $126^\circ \pm 1^\circ$  to  $90^\circ$  in 52 min, which decreased to 47, 38, and 24 min, respectively, when 3 V, 6 V and 9 V were applied during the 1st hour. Imbibition was further accelerated during the 2nd hour of EH; for instance, when voltages of 3 V, 6 V, and 9 V were introduced, it took 38, 22, and 17 min to reach  $90^\circ$  (Table 6).

This faster water imbibition induced by EH could be due to two effects. Firstly, the viscosity of water decreases with temperature from 1.0 mPa.s at  $20^\circ\text{C}$  to 0.28 mPa.s at  $100^\circ\text{C}$  [30]. The second effect, as quantified by the change in contact angle, is that the material becomes more water-wet. This is a temporary reversible change in that the contact angle returned to its original value 24 h after the EH was switched off, as seen in previous work [31]. We conclude that chalk wettability can be controlled by EH. These results are in line with previous work [25] where neodymium magnets were used to control the wetting behavior of carbonate rock – again, there was a significant effect (51 min to reach water-wet conditions for 0 T, 32 min for 4.8 T, and 17 min for 9.6 T), but it was also temporary.

The water composition (SW versus DW) also played a significant role, and SW imbibed faster, despite the slightly higher viscosity of SW; this is likely due to the presence of potential determining ions (PDIs) in solution causing a faster alteration in the contact angle [32]. For instance, the decline times to reach a contact angle  $90^\circ$  (for 0 V, no EH applied) were 40 min and 52 min, for SW and DW, respectively. However, after applying 9 V DC for 1 h, these times were reduced to 7.7 min and 26 min; this time reduction was further enhanced when 9 V were applied for 2 h (to 5.5 min for SW and 17 min for DW), Table 5, Fig. 4(a), Fig. 4(b) and Fig. 4(c). Also, a higher temperature is required for DW to reach  $90^\circ$ , for example, for 9 V, during the second hour, the temperature of DW ( $T = 109^\circ\text{C}$ ) was greater than that of Sw ( $T = 96^\circ\text{C}$ ) due to longer imbibition time of DW ( $t = 17$  min), compared to SW ( $t = 5.5$  min).

It should be mentioned that carbonate wettability also depends on water composition [33,34]. Furthermore, the EH changed the shape of the droplets as shown in Figs. 5 and 6, as discussed below.

### 3.1.2. Droplet shape

Figs. 5 and 6 display the shape of DW and SW droplets respectively. The images are extracted using the software DSA-100.

The water composition and applied voltage had a great impact on the decline time and the shape of the droplet, as shown in the above images (Figs. 5 and 6). In particular, our experiments demonstrated that under identical experimental conditions, the droplet's shape depends on the type of solution. Specifically, we observed that DW droplet was shorter and wider, compared to SW droplet under the same conditions (for example, compare the shape and size of DW and SW droplets on aged samples under 9 V in Figs. 5(b) and 6(b), respectively). Moreover, the

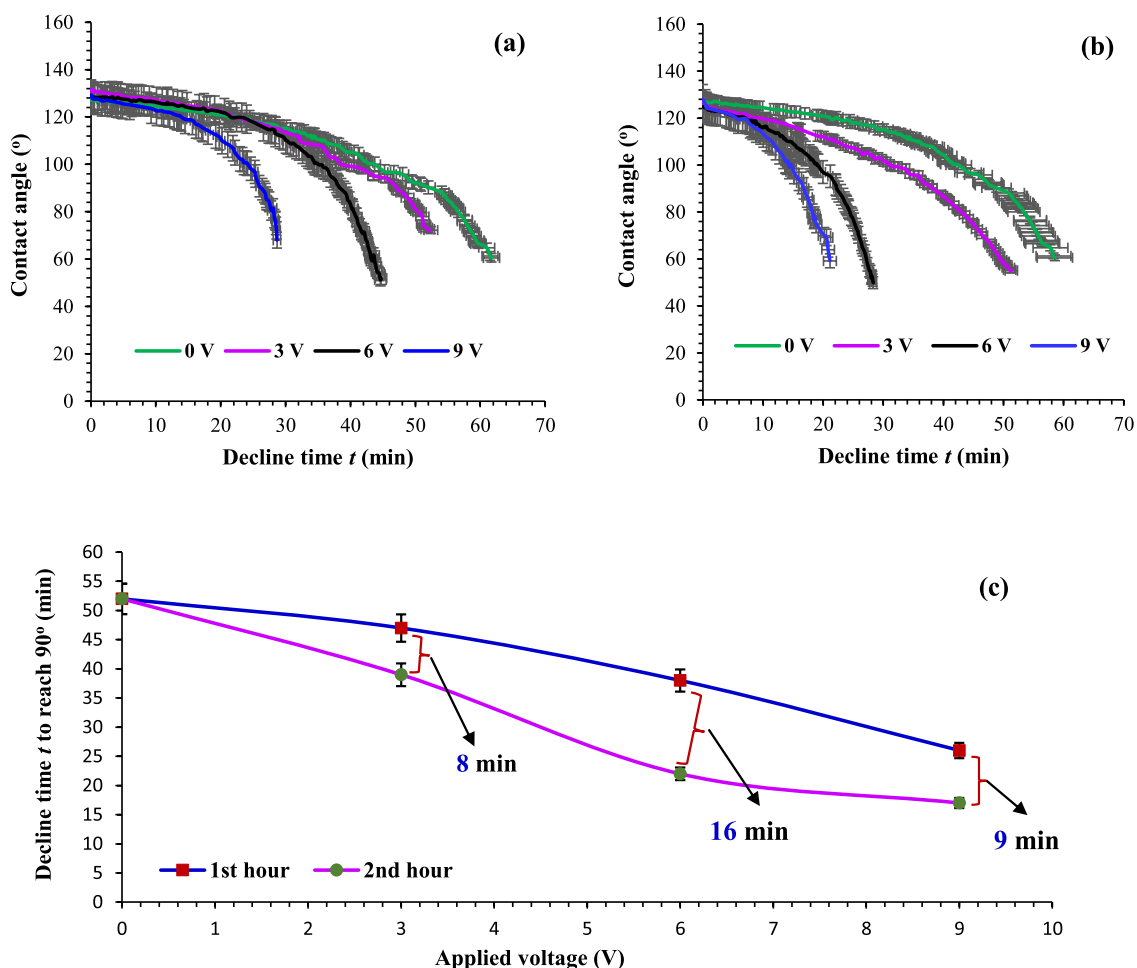


Fig. 3. Effect of EH on DW droplet contact angle during (a) the 1st hour and (b) the 2nd hour of the test. (c) Contact angle of a DW droplet as a function of applied voltage.

contact angle of SW was smaller than that of DW, which implied that SW was less oil-wet. We attribute this effect to the presence of  $\text{SO}_4^{2-}$  in SW, which made the system less oil-wet, consistent with previously published studies [35]. The applied voltage also had an effect with the contact angle decreasing more rapidly for larger voltages, as demonstrated in Figs. 5 and 6, and consistent with published studies [25,36].

### 3.2. Effect of EH on oil production

In this study, the effect of EH on rock properties was also examined to evaluate its ability in releasing oil from the porous media. Four core chalk samples were selected in this study: two water-wet and two initially oil-wet samples. The samples were immersed into DW or SW in an Amott cell and oil production was then recorded in the presence and absence of EH. The temperature was also recorded for all spontaneous imbibition tests. A DC current was applied up to 30 V during spontaneous imbibition. The heat (current) and magnetic field generated for each voltage are presented in Table 3.

In contrast to the water-wet samples, changing the imbibing fluids from DW Fig. 7(a) to SW Fig. 7(b) shows a remarkable impact on oil production from initially oil-wet samples where the recovery using DW as an imbibing fluid is 2.7% (core #3) and 11% for SW (core #4) in the absence of EH. As illustrated in Fig. 7(a) after applying EH, the total incremental oil recovery was increased to 13% DW (core #3) which is almost five times greater than of the sample without electricity. In Fig. 7 (b), where seawater (SW) is used as displacing fluid, applying a voltage increased the ultimate oil recovery to 26% (core #4), which is

equivalent to a two-fold increase. This is likely due to the heating effect of the imbibing fluid, which has an effect on modifying the wettability of the rock, as explained by the contact angle measurements (shown in Table 5, Figs. 3, and 4). In addition, heating lowers the viscosity of the water and oil. The highest oil recovery was observed with SW because of the presence of potential determining ions, which facilitate the change in surface charge, and hence, wettability. There is also a small contribution to recovery from the thermal expansion of the oil.

Fig. 7 shows oil production as a function of time while a summary of the ultimate oil recovery obtained is shown in Table 7. Recovery was enhanced due to the combined effects of a wettability change, without which there would be almost no imbibition into an initially oil-wet sample, and heating which reduces the viscosity of the oil and water. In previous work, the impact of magnetic field on oil recovery during spontaneous imbibition into initially oil-wet chalk samples was assessed, and it was found that oil recovery increased from 2.8% to 6.8% using DW, and from 12% to 19% using SW (compared to EH: 13% for DW and 26% for SW) in initially oil-wet systems when magnetic fields generated by neodymium magnets was applied [25]. We saw an effect on recovery in our experiments even with a magnetic field which is orders of magnitudes weaker than in previous work, implying that in this case heating, rather than the magnetic field itself, is the principal contributor to recovery [25,26]. A combination of heating and even a relatively weak magnetic field was sufficient to change the wettability of the samples. To identify the main mechanism responsible for improved oil recovery under the effect of applied DC current and associated magnetic and electric fields, future work covering additional targeted experiments and



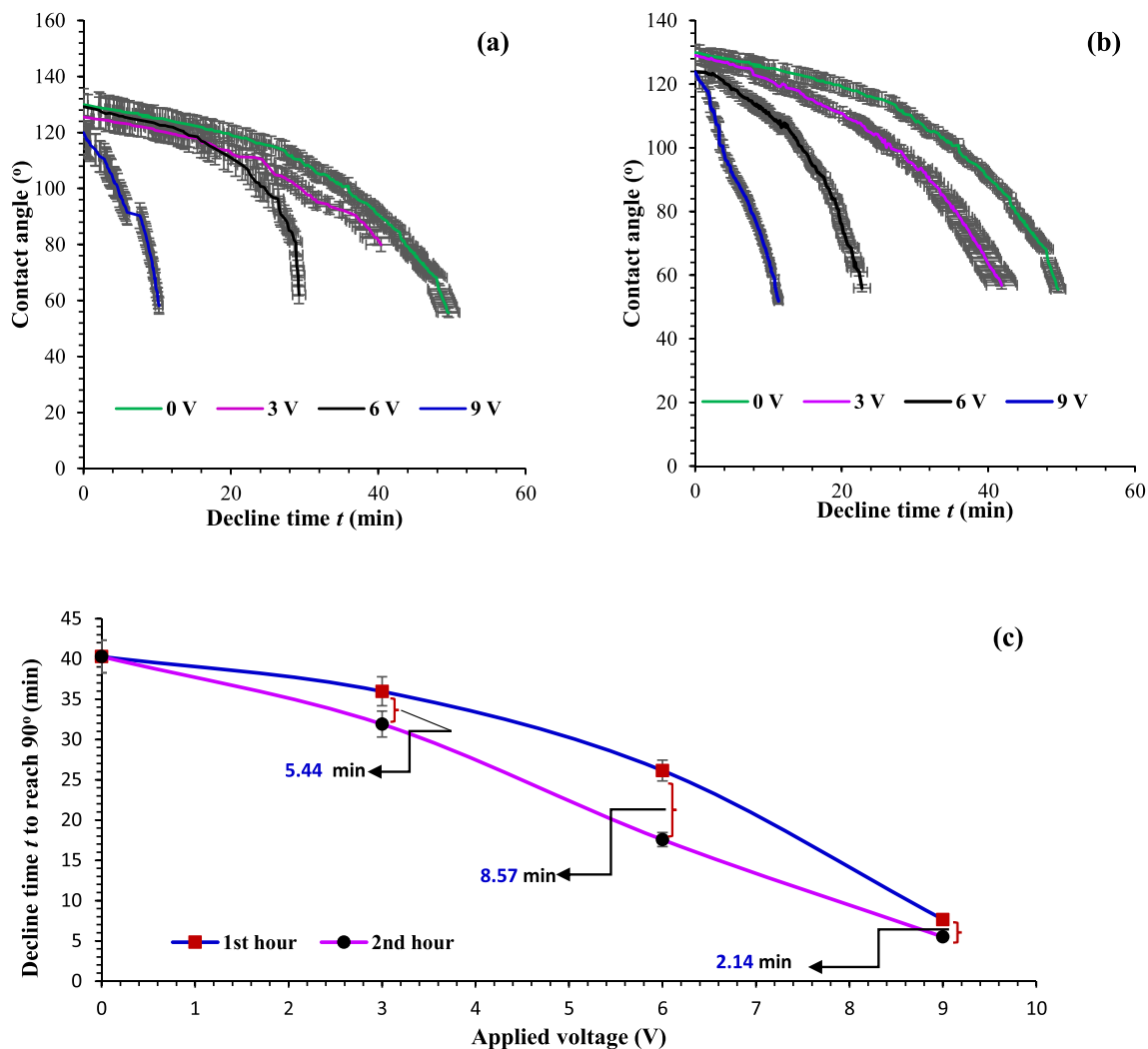


Fig. 4. Effect of EH on DW droplet contact angle during (a) the 1st hour (SW droplet) and (b) the 2nd hour (SW droplet) of the test (c) and contact angle (of SW droplet) as a function of applied voltage.

**Table 6**  
Oil recovery by EH in previous research.

Type of rock	Type of flooding	Oil recovery by means of EH (%)	Source
Sandstone	Water injection	16.2	[37]
Sandstone	Water injection	37	[38]
Sand pack	Water injection	12.4	[39]

modelling are planned.

### 3.3. Effect of EH on contact angle at the end of spontaneous imbibition

The samples were dried, crushed at the end of the spontaneous imbibition process and their surface charges and contact angles were measured; the results are presented in Table 8.

As can be seen in Table 8, the contact angle at the end of production of the water-wet samples (core #1 and core #2; when imbibed by DW and SW) were 3° for SW imbibition, compared to 8° for the sample imbibed by DW. Similar results were observed for the initially oil-wet samples: the contact angles were 84° for core #3 and 62° for core #4. Furthermore, a series of spontaneous imbibition experiments were carried out on chalk at different temperatures 70 °C, 100 °C, and 130 °C [40], and a significant improvement in oil production was observed. This is likely due to wettability alteration caused by the adsorption of

sulphate ions on the chalk rock surface at high temperature [35].

From Figs. 3–7, it is evident that EH has a great impact in altering wettability. Hence, it causes an increase in the oil production, as displayed in Fig. 7. Moreover, it is clear from Table 8, that introducing EH increased porosity values from oil-wet samples imbibed by SW from 11.31% to 12.69%. The highest contact angles values correspond to the lowest porosity values, indicating more compaction. The combined effect of the pre-heating and pre-magnetisation may have caused carboxylic group desorption (which when adsorbed helps the grains stick together). Hence, a magnetic field causes an increase in porosity [26]. The magnetic field has been found to increase porosity because magnetised water allows for better flow in porous media. For example, with different magnet strengths of 0 G, 3,000 G (0.3 T), and 6,000 G (0.6 T) and a total of 6 magnets each, the corresponding porosity values increased from 6.62% to 8.25% and 9.47%, respectively [41]. The degree of calcite dilation varies with heating temperature, resulting in the formation of new microcracks, separation along intragrain and/or intergrain boundaries, and widening of existing cracks, all of which cause an increase in porosity [42]. Also, it was found that when the core sample is subjected to a magnetic field, the permeability increased [43], and it was found that the permeability of dolomite increased at high temperature, whereas the one of limestone decreased [44].



Fig. 5. Images of DW droplets the in presence of EH (a) 1st hour, (b) 2nd hour of the test.

### 3.4. Effect of EH on surface tension

In this work, the surface tension of the aqueous phase was measured using a tensiometer before and after introducing electricity to the spontaneous imbibition process at room temperature, and the results are displayed in Table 9. Surface tension was measured between DW or SW and air in the presence/absence of EH. ‘Before’ means before introducing DW or SW to the rock, and ‘after’ means at the end of the spontaneous imbibition using DW or SW in the presence/absence of EH.

The surface tension measurements were conducted at room

temperature. Where heating had been applied, the system was first left to cool. As shown in Table 9, there was an obvious reduction in the surface tension of the aqueous phase, which was used as the displacing fluid for both water-wet and oil-wet systems. For instance, in a water-wet system imbibed with DW and SW, the surface tension of the imbibing fluid was reduced from 63.7 mN/m and 44.4 mN/m to 48.5 mN/m and 33.7 mN/m, respectively. For the initially oil-wet cores, the change in surface tension was even greater; for cores imbibed with DW and SW, the surface tension of the displacing fluid was decreased from 63.73 mN/m to 45.4 mN/m, and from 44.4 mN/m to 31.6 mN/m

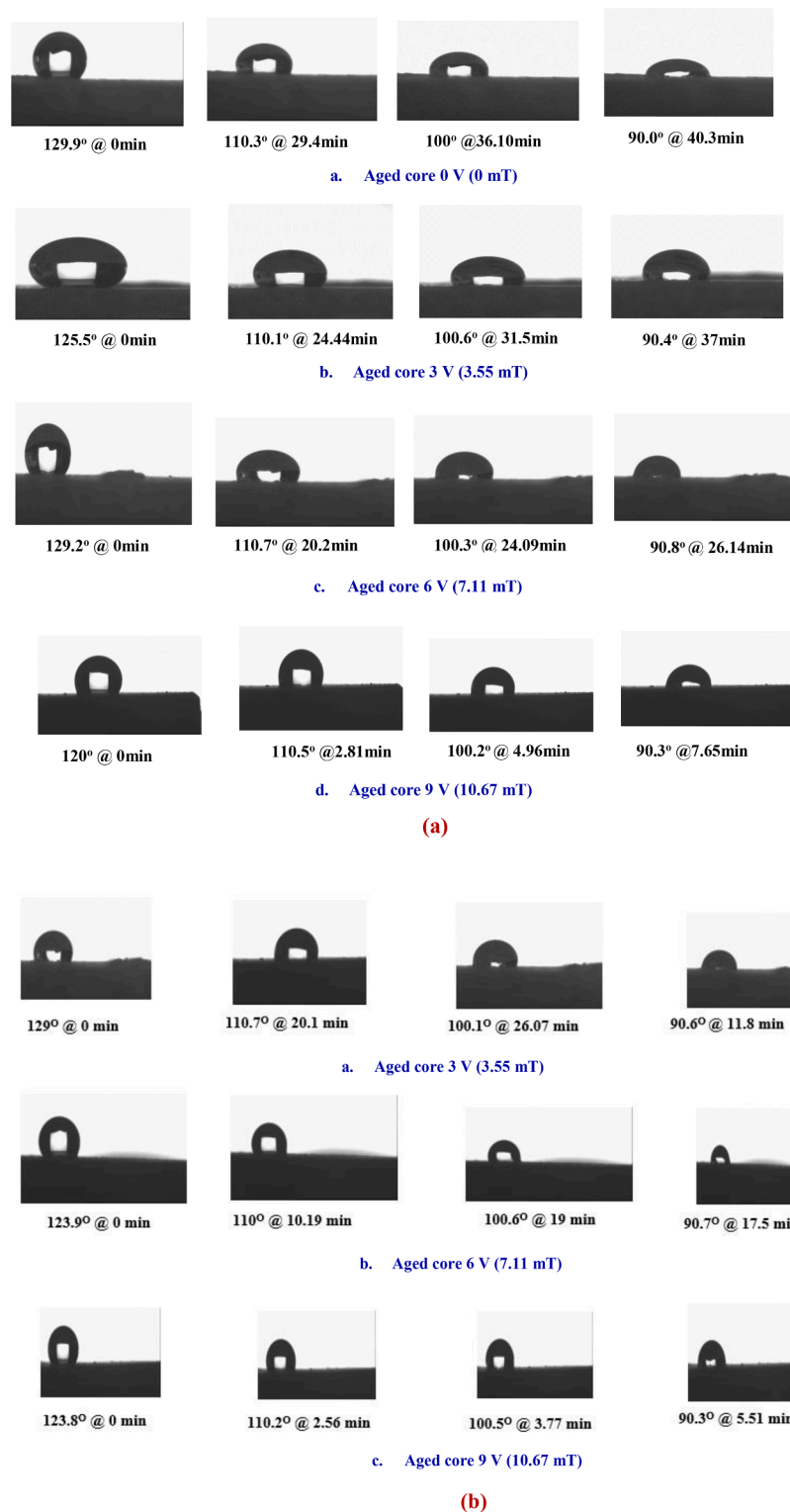


Fig. 6. Images of SW droplet the in presence of EH (a) 1st hour, (b) 2nd hour of the test.

respectively.

#### 4. Conclusions

This research investigated the effects of DC EH on oil recovery through the spontaneous imbibition of deionized water (DW) and seawater (SW) into initially oil-wet and water-wet chalk samples, while also measuring contact angle, and surface tension. From the results, we

can conclude that:

1. EH led to a significant incremental oil recovery, with a 10% – 25% additional recovery factor from spontaneous imbibition.
2. EH changed the contact angle, making the initially oil-wet rock samples water-wet. This change in wettability was more rapid as the externally applied voltage increased.

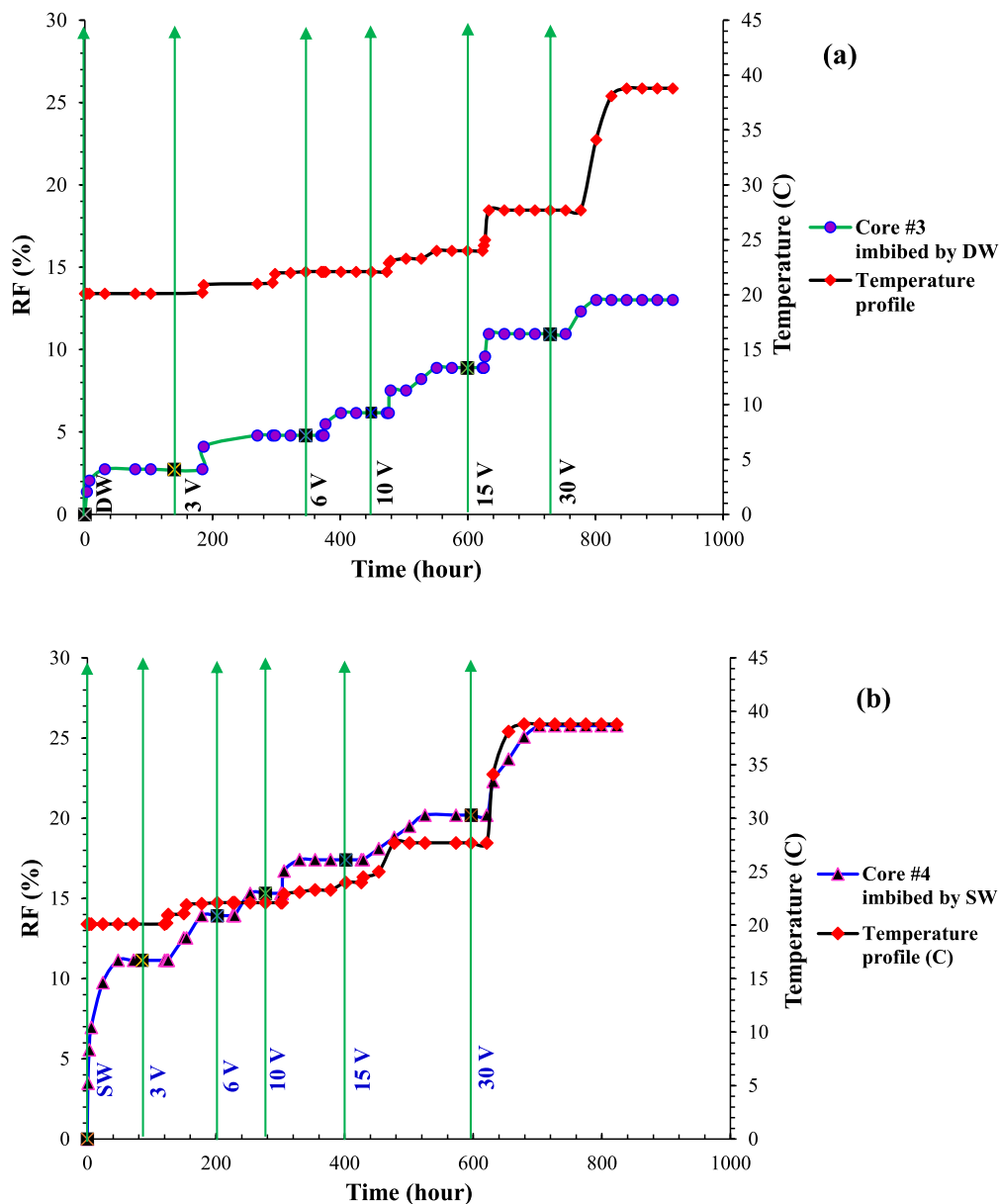


Fig. 7. Effect of EH on oil-wet chalk (a) OW DW, (b) OW SW.

- The surface tension of the aqueous solutions was found to decrease with increasing voltage, hence further contributing to improved oil recovery.

Based on the results obtained in this work, we recommend EOR as an economically viable method of increasing oil recovery. Possible future work includes larger-scale field tests and laboratory studies, to assess the independent effects of a magnetic field and heating on wettability change and recovery, and a more thorough petrophysical analysis of the samples, including the quantification of the change in permeability induced by heating. Furthermore, we recommend future research to identify the importance of the type of heating (either electrical or with an associated magnetic field) and the key EOR mechanisms responsible for improved oil recovery (wettability alteration, oil viscosity reduction, or decrease of interfacial tension). We conclude that with appropriate further work and development, enhanced oil recovery (EOR) using electrical heating from renewable power sources may provide – when combined with carbon capture and storage (CCS) – an economically and environmentally viable method for improving

recovery from mature oil fields.

#### CRediT authorship contribution statement

**Farida Amrouche:** Conceptualization, Methodology, Writing – original draft, Data curation, Formal analysis, Investigation, Project administration, Funding acquisition, Software, Validation, Resources, Visualization, Writing – review and editing. **Donglai Xu:** Validation, Resources, Data curation. **Michael Short:** Conceptualization, Visualization, Writing – review and editing. **Stefan Iglauer:** Visualization, Writing – review and editing. **Jan Vinogradov:** Data curation, Formal analysis, Investigation, Writing – review, and editing, Validation. **Martin J. Blunt:** Data curation, Formal analysis, Visualization, Writing – review and editing.

#### Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence

**Table 7**

Oil recovery factors RF (%) during spontaneous imbibition using DW or SW as imbibing fluids in the presence and absence of EH.

Core No	Wetting condition	Imbibing fluid	Total RF %	Incremental oil production (RF %) from EH
Core #1	Water-wet (WW)	DW	23.94	0
		DW + 3 V	27.46	3.52
		DW + 6 V	28.16	0.70
		DW + 10 V	30.98	2.82
		DW + 15 V	33.09	2.11
		DW + 30 V	37.32	4.23
Core #2	Water-wet (WW)	SW	26.98	0
		SW + 3 V	28.57	1.59
		SW + 6 V	29.36	0.79
		SW + 10 V	30.16	0.80
		SW + 15 V	36.50	6.34
		SW + 30 V	39.68	3.18
Core #3	Oil-wet (OW)	DW	2.74	0
		DW + 3 V	4.79	2.05
		DW + 6 V	6.16	1.37
		DW + 10 V	8.90	2.74
		DW + 15 V	10.96	2.05
		DW + 30 V	13.01	2.05
Core #4	Oil-wet (OW)	SW	11.14	0
		SW + 3 V	13.93	2.79
		SW + 6 V	15.32	1.39
		SW + 10 V	17.41	2.09
		SW + 15 V	20.20	2.79
		SW + 30 V	25.77	5.57

**Table 8**

Contact angle measurements for chalk surfaces after SI using DW and SW as imbibing fluids exposed to EH.

Cores	Contact angle (°)	Pellet porosity (%)
<b>Unmodified chalk</b>		
Water-wet (WW) without imbibition (no EH)	45	13.87
Deionized water water-wet (DW WW) reference core (no EH)	10	14.41
Core #1 DW WW + EH	8.0	14.63
Seawater water-wet (SW WW) reference core (no EH)	6.8	14.22
Core #2 SW WW + EH	3.0	15.71
<b>Modified chalk</b>		
Oil-wet (OW) without imbibition (no EH)	126 ± 1	6.60
DW OW reference core (no EH)	105	7.87
Core #3 DW OW + EH	84	9.21
SW OW reference core (no EH)	89	11.31
Core #4 SW OW + EH	62	12.69

**Table 9**

Effect of EH on surface tension aqueous phase in spontaneous imbibition process.

Surface tension (mN/m)		Average		STD	
		Core #1 -DW-		Core #2 -SW-	
WW system	Before applying EH	63.7	0.02	44.4	0.01
	After applying EH	48.5	0.01	33.7	0.05
		Core #3 -DW-		Core #4 -SW-	
OW system	Before applying EH	63.7	0.01	44.4	0.01
	After applying EH	45.4	0.08	31.6	0.01

the work reported in this paper.

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**Appendix A. Supplementary data**

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.fuel.2022.124559>.

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