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Analysis of the bounded and unbounded forms of USBM wettability index

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ABSTRACT

Understanding wettability is important in many processes where porous media and fluids are in contact. The U.S. Bureau of Mines (USBM) is one of the industry standard techniques for measuring wettability. This index is calculated as $USBM = lg\left(\frac{A_1}{A_2}\right)$, where A_1 and A_2 are the areas under capillary pressure curves of oil-drive and water-drive processes, respectively. Usually, the USBM is mistakenly assumed to vary over the range of −1 to 1 and compared with other indices. In this study we indicate that the lower and upper bounds of this index are not fully known in practice. As a result, comparison between USBM and other indices may cause erroneous interpretations due to dissimilar ranges of variation. In addition, even during examining the USBM of a sample it may not be possible to accurately interpret its wettability. We highlight the bounded form of the USBM index (denoted as $USBM^* = \frac{A_1-A_2}{A_1+A_2}$), which varies over the range of −1 to 1, and suggest that it should replace the traditional form of USBM index. Twenty limestone core-plugs were collected from Asmari and Fahlian formations in two Iranian fields. These samples were used for performing primary imbibition relative permeability measurements, as well as primary imbibition and secondary drainage capillary pressure tests. These experiments are used to show the differences between USBM and USBM* in comparative studies and compare them against other indices of Amott-Harvey, Lak and modified Lak.

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1. Introduction

Wettability is defined as the affinity of a solid surface to be in contact with one fluid in the presence of other fluids (Donaldson and Alam, 2008). This property results from intermolecular interactions when a solid surface and fluids are brought together (Lee, 1993; Jarray et al., 2020). Wettability is recognized as one of the foremost factors influencing multiphase flow, heat transfer, solute transport, and electrical current in synthetic and natural porous media (Armstrong et al., 2021; Ekechukwu et al., 2021). Since, saturation-dependent properties such as relative permeability and capillary pressure are functions of wetting state, the displacement rate of fluids and their residual saturations are dependent on wettability, as well (McPhee et al., 2015; Farahani et al., 2019). As a result, the knowledge of wettability is of noteworthy importance in many processes in geosciences where rocks and fluids are in contact, such as geological CO_2 storage in aquifers and hydrocarbon bearing strata (Chalbaud et al., 2009), primary, secondary and tertiary oil recovery (Al-Futaisi and Patzek, 2003; Christensen and Tanino, 2018), displacement of nonaqueous phase liquid (NAPL) and water during contamination and remediation of soils and aquifers (Al-Raoush, 2009; Molnar et al., 2020), and productivity/injectivity impairment in porous system of hydrocarbon reservoirs (Mirzaei-Paiaman et al., 2012).

Unlike the smooth and plain surfaces which are normally associated with homogenous and uniform wetting characteristics, pore spaces of natural porous media are often represented by heterogeneous and nonuniform wettabilities (Iglauer et al., 2012). While some pore surfaces may tend to be water-wet (or hydrophilic), other surfaces may be of oil-wetness character (or hydrophobicity). As a result, several variants of wettability such as water-,

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oil-, mixed-, and fractional-wetness may occur in practical situations (Anderson, 1986; Singh et al., 2016). Such heterogeneous wetting characteristics are mainly because of broad pore and pore-throat size distributions, surface roughness, and complex mineralogy in geological porous systems (Skauge et al., 2007). Therefore, in practice, macroscopic wettability of a rock/oil/brine system is the average of wetting characteristics at micro scale. Contact angle measurements, as direct wetting indicators, are suitable for smooth and plain surfaces, whereas reservoir rocks are represented by networks of rough and irregular pore surfaces (Anderson, 1986). Due to the inadequacy of traditional contact angle measurements in such media, alternative indirect methods are sought to infer the average wettability. Alternative methods are indirect as they are based on the analysis of wetting responses, instead of wetting itself. For example, capillary pressure measurements are affected by wettability, and thus their analysis may give indirect estimates of wetting (Longeron et al., 1995; Ma et al., 1999).

Quantitative methods that use measurements such as forced displacement capillary pressure, spontaneous and forced displacement volumes, rate of spontaneous imbibition, spontaneous capillary pressure, and relative permeability, tend to offer indices to describe the degree of wetness using numbers. These indices include Amott-Harvey (Boneau and Clampitt, 1977; Trantham and Clampitt, 1977), U. S. Bureau of Mines (USBM) (Donaldson et al., 1969; Sharma and Wunderlich, 1987), MPMS (Mirzaei-Paiaman et al., 2013, 2017), Lak (Mirzaei-Paiaman, 2021), modified Lak (Mirzaei-Paiaman et al., 2021), relative pseudo work of imbibition (Ma et al., 1999), LH (Longeron et al., 1995), normalized water fractional flow (Ferreira et al., 2017), and NMR-based techniques (Fleury and Deflandre, 2003; Al-Mahrooqi et al., 2006; Chen et al., 2006; Tandon et al., 2020).

Amott-Harvey and USBM are industry standard techniques (McPhee et al., 2015). In the USBM method, which is the subject of this article, the areas under forced displacement capillary pressure curves were used to define an index (Donaldson et al., 1969). The area under capillary pressure curve of a forced displacement process (i.e., a forced primary imbibition, or forced secondary drainage) is assumed to reflect the work necessary for one fluid to displace another fluid in that process. As a result, this index compares the relative works done in forced primary imbibition (or water drive) and forced secondary drainage (or oil drive) processes. The main drawback of the Amott-Harvey index is that the neutral wetting state cannot be measured. This is because when the rock is neutrally wet; neither water nor oil can be freely imbibed into the core. The USBM, Lak, and modified Lak methods have the advantage that they take into account the neutral wettability.

The areas under the capillary pressure curves of oil and water drive processes are denoted as A_1 and A_2 to define USBM index as (Donaldson et al., 1969):

$$USBM = lg\left(\frac{A_1}{A_2}\right). \quad \text{Eq. 1}$$

Water-wet porous media are characterized with positive values of USBM index, because in such systems A_1 is greater than A_2. This index becomes negative for oil-wet systems where A_2 is greater than A_1. In the standard USBM method, as developed by Donaldson et al. (1969), the water drive process starts from irreducible water saturation and continues until residual oil saturation. Also, the oil drive process starts from residual oil saturation and ends at a saturation very close to irreducible water saturation (Fig. 1A). Due to the absence of spontaneous processes in the standard USBM configuration, Dullien and Fleury (1994) concluded that the measurements conducted during water- and oil-drive processes are not true capillary pressures since they have been measured under dynamic and non-equilibrium conditions. Sharma and Wunderlich (1987) proposed a modified USBM setup where forced displacement measurements are performed only after the spontaneous intakes of fluids stop (Fig. 1B).

Although the USBM index is usually assumed to be varying in the range of −1 to 1 (Anderson, 1986; Man and Jing, 2002; Skauge et al., 2003; Ghedan and Canbaz, 2014; Valori and Nicot, 2019), the mathematical formulation used to calculate this index reveals that it is theoretically unbounded and can vary from $-\infty$ to $+\infty$ (see Eq. (1)). USBM values smaller than −1 or greater than 1 have also been reported in several case studies by Sharma and Wunderlich (1987), Longeron et al. (1995), Crocker (1986), Hirasaki et al. (1990), Dixit et al. (2000), Looyestijn and Hofman (2006), Vevle (2011), Man and Jing (2002), Abdallah et al. (2007), and Valori et al. (2017). Thus, in actual cases, this index should not be regarded as bounded in the range of −1 to 1. The USBM index is often compared against other indices, without paying attention to the fact that other indices are bounded in the range of −1 to 1. In the study, such dissimilar ranges and scales may be considered to cause unfair comparisons and erroneous interpretations. For example, while Amott-Harvey of −1 represents the highest level of oil wetness, USBM of −1 does not mean a similar level of wetting. In addition, even during examining USBM value of a given sample it may not be possible to accurately interpret its wettability because in practice the lower and upper bounds of the index are not fully known.

To resolve the above issues, a bounded form of USBM (denoted as USBM*) which varies in the range of −1 to 1, was previously used in a few publications where NMR-based wettability indices were checked against it (Looyestijn and Hofman, 2006; Looyestijn, 2008; Al-Muthana et al., 2012; Valori et al., 2017; Al-Ofi et al., 2018; Sauerer et al., 2019; Al-Garadi et al., 2022). However, the main message of these studies was not the need for replacing USBM by USBM*. Thus, USBM* has been overlooked, and petroleum engineers and geoscientists have not paid enough attention to it so far. This paper calls attention to USBM* and highlights the need to replace USBM with USBM*. In the bounded form of USBM index, in addition to the method being comparable to other indices, the resolution near neutral wettability is improved. Previous analyses were not with the formality and generality of the examinations performed in this article. We use a larger collection of twenty samples with variation in petrophysical properties to show the differences between USBM and USBM* in comparative studies, and consider several other indices (i.e., Amott-Harvey, Lak, and modified Lak) to support the USBM*; while previous studies were limited to NMR-based wettability indices.

2. Bounded USBM wettability index

A different mathematical equation for the USBM wettability test can be developed which is bounded (i.e., always falling in the range of −1 to 1) and still uses the areas under water and oil drive curves (i.e., A_1 and A_2). The bounded USBM (i.e., USBM*) as defined in Eq. (2) is positive for water-wet systems, where $A_1 > A_2$, and negative for oil-wet media, where $A_1 < A_2$.

$$USBM^* = \frac{A_1 - A_2}{A_1 + A_2} \quad \text{Eq. 2}$$

Combining Eqs. (1) and (2), the relationship between USBM and USBM* results as:

$$USBM^* = \frac{10^{USBM} - 1}{10^{USBM} + 1} \quad \text{Eq. 3}$$

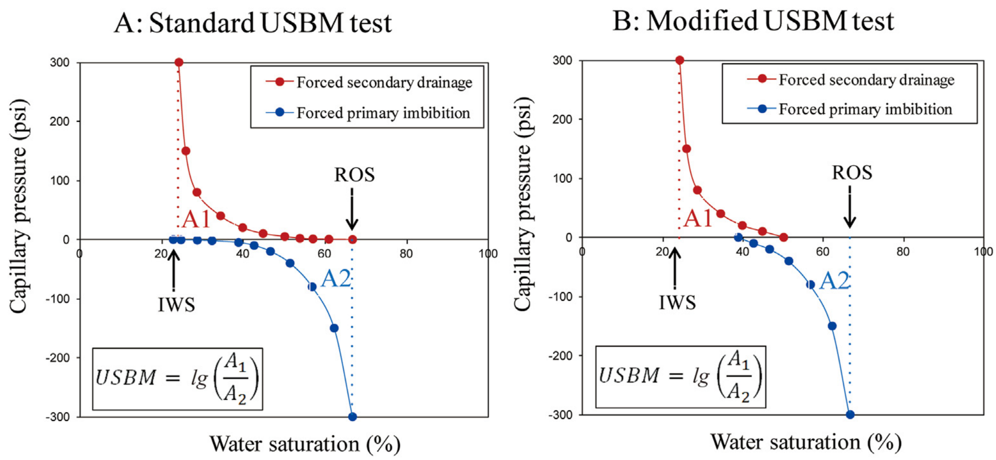

Fig. 1. Schematic representation of the standard (plot A) and modified (plot B) USBM tests (IWS and ROS stand for irreducible water saturation and residual oil saturation, respectively).

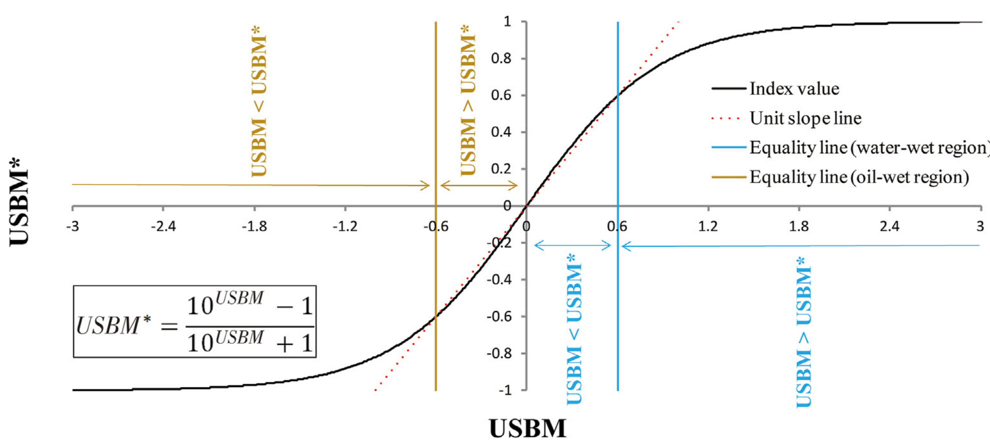

Fig. 2. Graphical relationship between USBM and USBM*.

Eq. (3) can be used to draw the graphical relationship between USBM and USBM* as shown in Fig. 2. In this figure, the range of USBM on the x-axis is put from −3 to 3 mainly because outside this range the USBM* experiences very small changes such that the curve looks flat. As USBM values approach -∞ and ∞, USBM* becomes −1 and 1, respectively. As displayed in this figure, in the case of water-wet systems, the USBM values from 0.6 to ∞ scale down to the USBM* values varying from 0.6 to 1 (i.e., USBM > USBM*) whereas USBM values smaller than 0.6 scale slightly up once transformed into the USBM* domain (i.e., USBM < USBM*). For oil-wet systems, the USBM values between −0.6 and -∞ scale up to the USBM* values from −0.6 to −1 (i.e., USBM < USBM*) whereas USBM values greater than −0.6 scale slightly down once transformed into the USBM* domain (i.e., USBM > USBM*).

3. Sample preparation

All stages of sample preparation and performing displacement tests are summarized in Fig. 3. These stages will be described as follows.

3.1. Cleaning, drying and porosity-permeability measurements

A total of twenty limestone samples of 1.5-inch diameter and 2-inch length are applied in the study. These samples were collected from the Asmari (eight samples, dataset 1) and Fahlian (12 samples, dataset 2) formations of two Iranian fields. The plugs were cleaned using Toluene and Methanol to eliminate drilling mud contaminants and other impurities (i.e., organic matters, hydrocarbons and salts) and dried up for 48 h at elevated temperature following RP40 standard (API, 1998). Then, helium porosity and air permeability measurements were performed (Table 1).

3.2. Rock typing

To identify the single-phase rock types and study the heterogeneity, GHE* template was used (Mirzaei-Paiaman et al., 2020). This template consists of ten predefined rock types each covering a specific range of FZI* values (Eq. (4)), as displayed in Fig. 4. In this template, each line which corresponds to a particular FZI* value represents the lower limit of a predetermined reference rock type (referring to Mirzaei-Paiaman et al. (2020) for further details). As one moves bottom up to the top of this template, rock type quality increases. Regarding our plugs, two rock types of 3 and 4, and four rock types of 3, 4, 5 and 6 were found for the datasets 1 and 2, respectively (summarized in Table 1 and shown in Fig. 4). This implies that dataset 2 is more heterogeneous than dataset 1. It is worthy to mention that Mirzaei-Paiaman et al. (2015, 2018) presented FZI* as a modified FZI (Amaefule et al., 1993). Moreover, Corbett and Potter (2004) developed the original GHE template

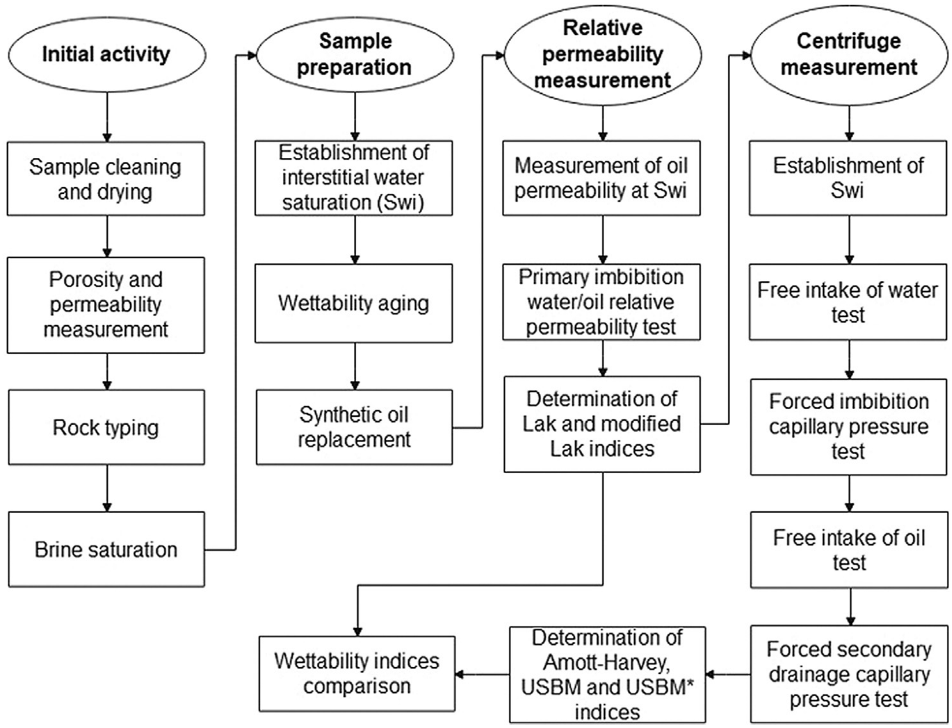

Fig. 3. Stages of sample preparation and performing displacement tests.

Table 1
Properties of the plugs used in the tests.

Dataset	Plug no.	Porosity (%)	Permeability (mD)	*FZI** (μm)	GHE* no.
1	1	17.45	1.67	0.10	3
	2	19.38	2.98	0.12	4
	3	18.98	4.39	0.15	4
	4	18.63	1.04	0.07	3
	5	16.14	1.99	0.11	3
	6	21.57	4.93	0.15	4
	7	15.66	1.92	0.11	3
	8	17.84	4.01	0.15	4
2	1	19.18	7.41	0.20	4
	2	19.67	0.82	0.06	3
	3	21.14	3.994	0.14	4
	4	22.81	186.77	0.90	5
	5	16.68	94.06	0.75	5
	6	24.25	983.48	2.00	6
	7	17.89	9.24	0.23	4
	8	11.01	3.54	0.18	4
	9	15.19	19.27	0.35	4
	10	14.45	0.64	0.07	3
	11	14.61	6.12	0.20	4
	12	19.74	6.51	0.18	4

based on FZI values.

$$FZI^{*} = 0.0314\sqrt{\frac{K}{\varphi}} \quad \text{Eq. 4}$$

Where *FZI**, absolute permeability (K), and effective porosity (φ) are in micrometer, mD, and fraction, respectively (Mirzaei-Paiaman et al., 2015, 2018).

3.3. Saturation

The clean and dry samples were placed in a sealed container, and then evacuated up to a vacuum pressure of 0.001 psi. Next, the container was filled with a 190,000 ppm of equivalent NaCl brine and gradually pressurized up for at least 4 h to a fixed pressure of 2000 psi. Brine-saturated plugs were aged in the solution no less than ten days to reach ionic equilibrium. Brine salinity and ionic equilibrium with carbonate surface has strong effect on the subsequent wettability restoration process, where oil-wetness increases with salinity (Shaik et al., 2020). The wettability alteration of carbonate surfaces from water-wet state to oil-wet state with the increase in salinity can be explained from the effect of NaCl concentration on the surface charge. The increase in the positive surface charge density could promote adsorption of negatively charged acidity crude oil onto the carbonate surface and render them oil-wet. The author's experiences show that ten days is good for ionic balance.

3.4. Establishment of interstitial water saturation

Brine-saturated plugs were transferred to the core holder and a number of pore volumes of brine were injected. Then, they were placed in the centrifuge for conducting primary drainage water-oil capillary pressure measurements at 50 °C where dead crude oil pushed brine out at a series of centrifugal speeds until interstitial water saturation.

3.5. Wettability restoration

Carbonate rock is naturally water-wet, but, adsorption of polar components such as asphaltenes, resins, and carboxylic acids and/or deposition of the organic material onto the rock surface renders it mixed-wet or oil-wet (Anderson, 1986; Dubey and Waxman, 1991). After establishment of interstitial water saturation, wettability of samples was restored by aging in crude oil at reservoir temperature of 70 °C for two weeks. The optimal aging time for carbonate samples has been studied by Shaik et al. (2020). The extent of wettability reversal of an originally water-wet rock by

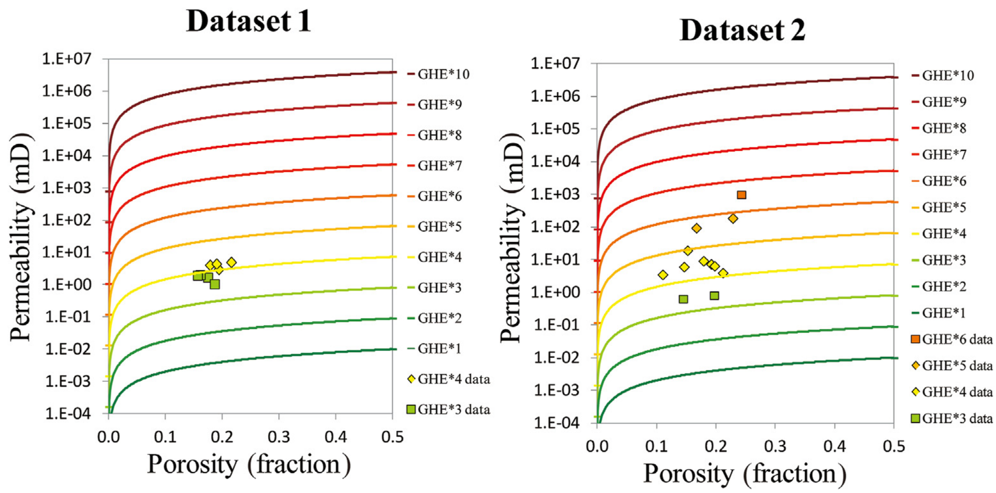

Fig. 4. Position of plugs on the GHE* template for single-phase rock typing.

surface active agents depends on mineral composition, pressure, temperature, brine chemistry and ionic composition (Anderson, 1986). In commercial laboratories, the use of equivalent NaCl brine is common instead of composite brine. The reason is the creation of unwanted scales and deposits in the composite brine. Carbonate samples are positively charged in equivalent NaCl brine with high Na^+ concentration. Negatively charged acidic compounds of crude oil such as naphthenic acids in aging process can diffuse through the water film and chemisorb onto the rock surface.

3.6. Synthetic oil replacement

The crude oil was flushed out with decahydronaphthalene (decalin) which itself was displaced by synthetic oil (n-Decane). Decalin was used as a buffer between the synthetic oil and the crude oil to avoid impurity precipitation. Synthetic oil and brine were used during all subsequent experiments. This was performed to prevent operational difficulties and problems associated with injection of dead crude into the tight carbonate samples.

4. Laboratory test procedure

Our experiments are divided into two sequential categories: (1) Unsteady-state water/oil imbibition relative permeability in order to measure Lak and modified Lak wettability indices; (2) Free imbibition and forced capillary pressure measurements to calculate Amott-Harvey, USBM and USBM* indices. These experiments have been used in our previous study, as well, but for a different purpose (Mirzaei-Paiaman et al., 2021). Table 2 lists the properties of the fluids used.

4.1. Relative permeability measurement

- The oil permeability at interstitial brine saturation was measured by synthetic oil.
- Primary imbibition unsteady-state water displacing oil measurements were performed.
- The Jones and Roszelle (1978) method was used to calculate relative permeability.

4.2. Free imbibition and forced capillary pressure measurements

- The brine saturated samples (at residual oil saturation) were centrifuged at room conditions under synthetic oil to reach irreducible water saturation.
- Plugs were placed in Amott cell for measuring the spontaneous imbibition volume of brine.
- After the spontaneous process, the samples were centrifuged under brine at several speeds to perform the forced imbibition capillary pressure measurements.
- Spontaneous intake of oil was simulated in Amott cell.
- Samples were centrifuged under oil to run the forced secondary drainage capillary pressure experiments.

5. Wettability measurement methods

The areas under the measured forced primary imbibition and forced secondary drainage capillary pressure curves are used to obtain the USBM (Eq. (1)) and USBM* (Eq. (2)) indices. Moreover, the water saturation changes corresponding to each of the spontaneous and forced displacement processes were used to calculate the Amott indices to water and oil (Amott, 1959), and consequently the Amott-Harvey index (Boneau and Clampitt, 1977; Trantham and Clampitt, 1977) as:

$$I_w = \frac{V_{o,SD}}{V_{o,SD} + V_{o,FD}} \qquad \text{Eq. 5}$$

Table 2
Specifications of the fluids used in the tests.

Property test	Water density (gr./cc)	Oil density (gr./cc)	Interfacial tension (dyne/cm)	Water viscosity (cp)	Oil viscosity (cp)
Primary drainage capillary pressure at 50 °C	1.125	0.857	26.79	-	3.29
Imbibition/secondary drainage capillary pressure at 25 °C	1.145	0.731	-	1.36	2.44
Relative permeability at 25 °C	1.145	0.731	-	1.36	2.44

$$I_o = \frac{V_{w,SD}}{V_{w,SD} + V_{w,FD}} \quad \text{Eq. 6}$$

$$I_{AH} = I_w - I_o \quad \text{Eq.7}$$

Where I_{AH} is Amott-Harvey index, I_w is Amott water wettability index, I_o is Amott oil wettability index, $V_{o,SD}$ is the volume of oil spontaneously displaced by the intake of water, $V_{o,FD}$ is the volume of oil displaced by the forced imbibition of water, $V_{w,SD}$ is the volume of water spontaneously displaced by the intake of oil, and $V_{w,FD}$ is the volume of water displaced by the forced penetration of oil.

The imbibition relative permeability data were used to determine the values of Lak and modified Lak wettability indices. Lak wettability index (I_L) was defined as (Mirzaei-Paiaman, 2021):

$$I_L = \alpha\left(\frac{0.3 - k_{rw@S_{or}}}{0.3}\right) + \beta\left(\frac{0.5 - k_{rw@S_{or}}}{0.5}\right) + \frac{CS - RCS}{1 - S_{or} - S_{wc}} \quad \text{Eq. 8}$$

Where $k_{rw@S_{or}}$ is the water relative permeability at residual oil saturation (to use Lak index, water relative permeability should be expressed as the water effective permeability divided by the oil permeability at irreducible water saturation), CS is the water saturation at the crossover point of relative permeability curves, S_{or} is the residual oil saturation, S_{wc} is the irreducible water saturation, RCS is a reference crossover saturation (defined in Eq. (9)), and α and β are constant coefficients (defined in Eq. (10)). All saturations are expressed in fraction.

$$RCS = \frac{1}{2} + \frac{S_{wc} - S_{or}}{2} \quad \text{Eq. 9}$$

$$if \begin{cases} k_{rw@ROS} < 0.3, \ then \ \alpha = 0.5\ ,\ \beta = 0 \\ 0.3 \le k_{rw@ROS} \le 0.5, \ then \ \alpha = \beta = 0\,. \\ k_{rw@ROS} > 0.5, \ then \ \alpha = 0\ ,\ \beta = 0.5 \end{cases} \quad \text{Eq. 10}$$

Modified Lak wettability index (I_{ML}) is expressed as (Mirzaei-Paiaman et al., 2021):

$$I_{ML} = \frac{A_o - A_w}{A_o + A_w}. \quad \text{Eq. 11}$$

Where A_o and A_w are the areas under the oil and water relative permeability curves, respectively.

The USBM and USBM* tests appear to be superior to the Amott test, which is insensitive near neutral wettability. It is possible to have an Amott-Harvey wettability index of about zero either because the material imbibes neither water nor oil strongly, or because it imbibes quite a bit of both to the same degree. However, the USBM and USBM* tests cannot determine whether a system is homogeneous in wettability or not, while the Amott test is sometimes sensitive. In some fractional or mixed-wet systems, both water and oil imbibe spontaneously. The Amott test will have positive displacement by water and displacement by oil ratios, indicating that the system is non-homogeneously wetted. Since wettability is the main function affecting relative permeability, the relative permeability curves can be a tool to obtain the sample wettability. On the other hand, because the heterogeneity of the sample affects the relative permeability curves, the wettability index obtained by Lak and modified Lak can indicate the mixed or fractional wettability of the sample. On the other hand, indices obtained from relative permeability can be more sensitive to neutral wettability.

6. Results and discussion

The measured forced primary imbibition and forced secondary drainage capillary pressure data, as well as the water saturation changes corresponding to each of the spontaneous and forced displacement processes are shown in Fig. 5. Correspondingly, imbibition relative permeability data are shown in Fig. 6.

The calculated values of different wettability indices are summarized in Table 3, which is used to prepare cross-plots of USBM and USBM* versus other indices, i.e., Amott-Harvey (Plots A), Lak (Plots B), and modified Lak (Plots C), as shown in Figs. 7 and 8 for datasets 1 and 2, respectively. On each plot included in these two figures, the dotted line shows the 1:1 line.

Regarding Figs. 7 and 8, for the samples with USBM values (depicted by green circles) smaller than −0.6, one may mistakenly conclude poor correlations between USBM and other indices mainly because these samples are located relatively far from the identity line. But, the application of USBM* (shown by red circles) shifts the data considerably up, which in this case is towards the 1:1 line. For the samples with USBM values greater than −0.6 and smaller than 0, the use of USBM* shifts the data slightly down, which can be towards or away from the line of equality, and it all depends on the sample itself. For the samples with USBM values greater than 0 and smaller than 0.6, the use of USBM* shifts the data slightly up, which can be towards or away from the identity line, and it all depends on the sample itself. As a result, since the theoretical and practical ranges of USBM variation are different

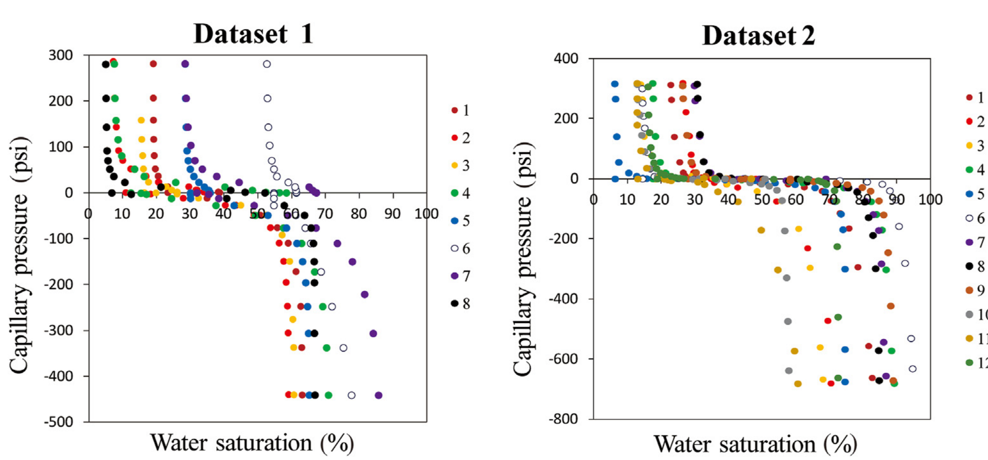

Fig. 5. The forced primary imbibition and forced secondary drainage capillary pressure data.

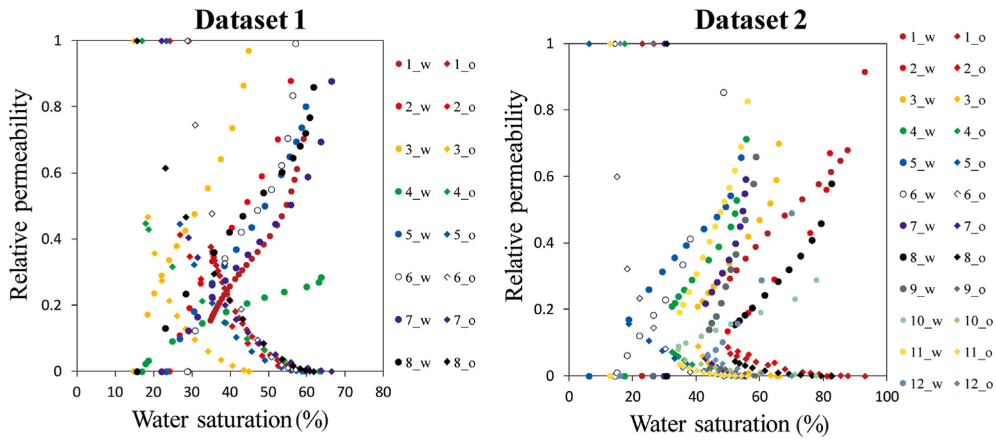

Fig. 6. The primary imbibition water-oil relative permeability data.

Table 3
The calculated values of different wettability indices.

Dataset	Plug no.	USBM	USBM*	Amott-Harvey	Lak	Modified Lak
1	1	−0.87	−0.76	−0.46	−0.37	−0.21
	2	−0.23	−0.26	−0.40	−0.61	−0.37
	3	−0.82	−0.74	−0.74	−0.74	−0.41
	4	−0.42	−0.45	−0.12	−0.05	0.00
	5	−0.82	−0.74	−0.76	−0.51	−0.36
	6	−0.95	−0.80	−0.57	−0.65	−0.20
	7	−0.52	−0.54	−0.26	−0.55	−0.27
	8	−0.21	−0.24	−0.21	−0.46	−0.12
2	1	−0.94	−0.79	−0.67	−0.69	−0.49
	2	−0.94	−0.79	−0.51	−0.29	−0.14
	3	−0.73	−0.69	−0.53	−0.35	−0.17
	4	−0.81	−0.73	−0.64	−0.46	−0.34
	5	−0.45	−0.48	−0.43	−0.40	−0.38
	6	−0.71	−0.67	−0.62	−0.53	−0.40
	7	−0.49	−0.51	−0.31	−0.24	−0.10
	8	−0.54	−0.55	−0.43	−0.29	−0.37
	9	−0.48	−0.50	−0.46	−0.32	−0.12
	10	−0.18	−0.21	−0.03	−0.14	−0.02
	11	−1.55	−0.95	−0.75	−0.53	−0.38
	12	0.05	0.06	−0.11	0.02	0.20

from other indices, it cannot be fairly compared with others. Thus, the cross-plots of USBM and other indices could be misleading and give inaccurate comparisons. Since the scale of USBM* is from −1 to 1, it can be efficiently compared to the others.

As mentioned earlier (Table 1 and Fig. 4), from single-phase rock quality point of view, the dataset 2 is more heterogeneous than the dataset 1. Two rock types of 3 and 4, and four rock types of 3, 4, 5 and 6 are observed for the datasets 1 and 2, respectively. For each wettability index we calculate the range (defined as the difference between maximum and minimum values). The calculated data are summarized in Table 4 for our datasets. As shown, the dataset 2 is more heterogeneous than the dataset 1 in terms of wettability. Thus, it seems there should be a correlation between single-phase rock quality and wettability heterogeneity because in both cases the second dataset is more heterogenous than the first one.

7. Conclusion

This study calls attention to the ranges of USBM variation and other wettability indices. The USBM index is often checked against other indices, ignoring the fact that unlike other indices which are bounded in the range of −1 to 1, USBM is not varying over this interval. To show the differences between USBM and its bounded form (i.e., USBM*) in comparative studies, two sets of primary imbibition and secondary drainage capillary pressure data, as well as the primary imbibition relative permeability information of twenty carbonate samples were used. The experimental data were used to compare USBM and USBM* against Amott-Harvey, Lak, and modified Lak wettability indices. In the case of using USBM, different scales may lead to unjust comparisons and flawed interpretations in comparative studies. Moreover, even during examining USBM of a sample it may not be possible to fairly interpret its wettability due to the unknown lower and upper bounds of the index. The traditional USBM equation should be replaced by USBM* which varies over the range of −1 to 1 in both theory and practice, similar to other indices.

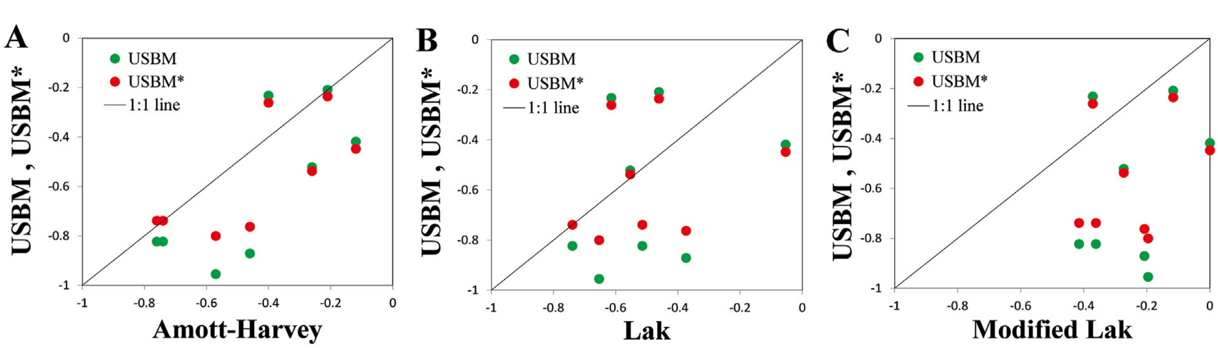

Fig. 7. Cross-plots of USBM and USBM* versus other indices for dataset 1.

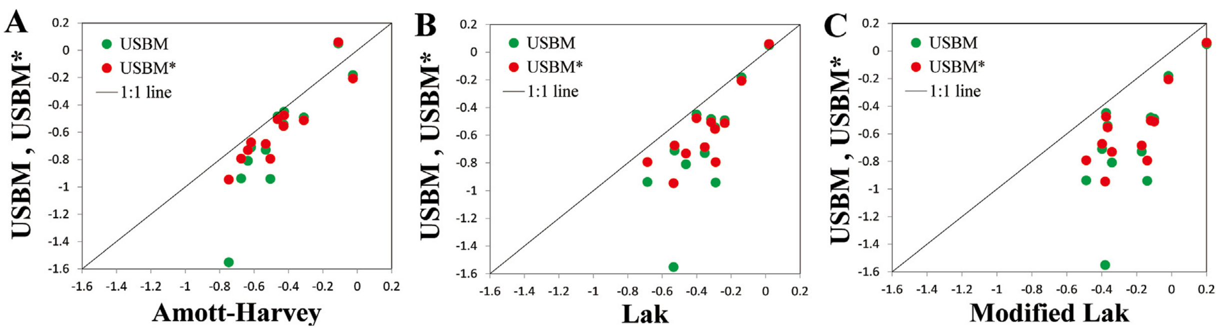

Fig. 8. Cross-plots of USBM and USBM* versus other indices for dataset 2.

Table 4
The range (difference between maximum and minimum values) of different wettability indices.

Dataset	USBM*	Amott-Harvey	Lak	Modified Lak
1	0.56	0.64	0.69	0.42
2	1.01	0.72	0.71	0.69

Declaration of competing interest

The author declares that he has no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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