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Wettability of Carbonate Reservoir Rocks: A Comparative Analysis

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Abstract: Various methods have been proposed for the evaluation of reservoir rock wettability. Among them, Amott–Harvey and USBM are the most commonly used approaches in industry. Some other methods, such as the Lak and modified Lak indices, the normalized water fractional flow curve, Craig's triple rules of thumb, and the modified Craig's second rule are based on relative permeability data. In this study, a set of capillary pressure curves and relative permeability experiments was conducted on 19 core plug samples from a carbonate reservoir to evaluate and compare different quantitative and qualitative wettability indicators. We found that the results of relative permeability-based approaches were consistent with those of Amott–Harvey and USBM methods. We also investigated the relationship between wettability indices and rock quality indicators RQI, FZI, and Winland R35. Results showed that as the rock quality indicators increased, the samples became more oil-wet.

Keywords: wettability; relative permeability; capillary pressure; rock quality; special core analysis

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1. Introduction

Wettability is a two- or multi-phase property defined as the preference of solid matrix of rocks to be in contact with one fluid rather than another [1]. It is one of the most critical properties controlling multiphase flow and transport in porous media [2–13]. Studies have shown that the wettability of rocks has a direct impact on relative permeability [4,10,14,15], capillary pressure [3,16], and performance of secondary and tertiary oil recovery methods [5,17,18]. A lack of knowledge of rock wetting behavior may lead to substantial uncertainties in the estimation of a reservoir's accessible oil and recovery rate [18–21]. Therefore, an advanced understanding of this parameter can significantly contribute to better assigning saturation functions to reservoir simulation models, modeling CO_2 geo-sequestration [22–24], and evaluation of formation damage [25–27] as well as assessing secondary and tertiary enhanced oil recovery efficiencies [21].

Typically, reservoir rocks are initially water-wet since rock particles tend to be solely in contact with brine [1]. However, as crude oil migrates into a reservoir from a source rock, heavier components of oil get adsorbed to the surface of rock over time. Accordingly, reservoir rocks incline towards have less water-wet tendency as they age. Several studies suggested that the wettability of reservoir rocks is a function of various parameters, including aging time [28,29], temperature [1,30], heavy components of the crude oil [1,29], mineral composition of the rocks [31], and pore structures [31].

In the literature, indirect evaluations of wettability have been performed by measuring petrophysical parameters affected by contact angle, e.g., relative permeability and capillary pressure curves [1,15,32]. Laboratory methods, such as Amott [33], Amott–Harvey [34,35], standard USBM [36], and modified USBM [37] have been widely applied in the oil industry. In addition, relative permeability-based techniques including Craig's triple rules of thumb [38], the normalized water fractional flow curve [39], Lak [15], and modified Lak [13] were proposed to deduce knowledge of wettability in rocks. There exist other wettability indicators, such as the relative pseudo work of imbibition [40], MPMS (MPMS stands for Mirzaei–Paiaman, Masihi and Standnes) [41,42], relative imbibition rate [43], rise in core [44], and NMR-based techniques [45–50] that require additional experiments.

Various studies have been conducted to evaluate wettability characteristics of reservoir rocks. For example, Treiber and Owens [51] measured contact angle by analyzing the droplet of oil on a polished crystal of reservoir rock on 50 reservoir rocks and noted that 64% of carbonate reservoirs were intermediate-wet, 28% oil-wet, and 8% water-wet. Chilingar and Yen [52] measured wettability of 161 carbonate samples using image analysis and concluded that 80% of the samples were oil-wet (100–180 degrees), 12% intermediate-wet (80–100 degrees), and 8% water-wet (0–80 degrees). Al-Yousef et al. [53] analyzed the wettability of Saudi Arabian carbonate reservoir rocks using the USBM, Amott, and CryoSEM methods and found that almost all samples were neutral to slightly oil-wet. Webb et al. [54] used displacement characteristics and indicated that preserved carbonate samples exhibited significantly more oil-wet character than restored samples. Marzouk [55] investigated the wettability of Thammama and Arab carbonate reservoirs in Abu Dhabi. The survey revealed oil-wet conditions in the oil zone, mixed-wet in the transition zone, and water-wet in the water zone. Okasha et al. [56] investigated the wettability of Arab carbonate reservoir using Amott, USBM, and relative permeability techniques as well as measurements of contact angle by analyzing the droplet shape placed on a smooth substrate (calcite plate). They stated that carbonate reservoir rocks analyzed in their study were generally ranged from slightly water-wet to slightly oil-wet. Okasha et al. [57] found that the results of the Amott and USBM methods were similar indicating that the Arab-D carbonate reservoir was slightly oil-wet. In another study, Al-Attar et al. [58] evaluated the Bu Hasa reservoir by measuring the contact angle by image analysis and showed the reservoir had slightly water-wet responses. Bakhshi and Torab [59] assessed the wettability of 17 core plug samples from three wells of an Iranian carbonate reservoir via the Amott–Harvey method. Their results showed that the Amott–Harvey index varied from −0.8 to 0.01 indicating oil-wet to slightly water-wet conditions. Chen et al. [60] studied wettability characteristics of a carbonate reservoir in the Middle East via optical-based contact angle measurements. They found that most of samples ranged between neutral-wet and slightly oil-wet. Recently, Faramarzi-Palangar and Mirzaei–Paiaman [61] analyzed the wettability of 25 core plug samples from an Iranian carbonate reservoir via Craig's triple rules of thumb and the Amott–Harvey index and reported that samples were oil-wet. Using the Lak index, Mirzaei–Paiaman [15] evaluated the wettability of ten plug samples from six carbonate reservoirs. His results showed that the Lak index for their samples varied from −0.64 to −0.19, which indicated oil-wet conditions. Mirzaei–Paiaman et al. [13] also reported the wetness of 20 core plug samples from two carbonate reservoirs of Asmari and Fahlian from the Middle East. Those authors used the Amott–Harvey, USBM, Lak, and modified Lak indices and found slightly water- to oil-wet conditions.

In the literature, various studies evaluated and compared the performance of wettability indices [62–64]. Anderson [32] stated that the USBM method performed better than the Amott method in differentiating near-neutral-wet systems. However, some studies argued that both the USBM and Amott methods may not accurately detect the type of wetness in strongly water-wet systems [40,62,63]. Dixit et al. [65] investigated the relationship between the Amott and USBM indices and found that these two methods provided similar results only in weakly-wetted media with randomly distributed water-wet and oil-wet pores.

The main objective of this study is to evaluate and compare different quantitative and qualitative wettability assessment methods including Amott, Amott–Harvey, and USBM as well as relative permeability-based techniques, such as Craig's triple rules of thumb, the modified Craig's second rule, the normalized water fractional flow curve, Lak, and modified Lak. For this purpose, a set of capillary pressure curves and relative permeability measurements was conducted on 19 core plug samples from a carbonate reservoir. The relationship between wetting indices and rock quality indicators is also discussed.

2. Wettability Measurement Methods

The Amott method [33] evaluates the impact of wettability based on the microscopic displacement efficiency. The Amott oil index is given by

$$I_O = \frac{V_{wsi}}{V_{wt}} \tag{1}$$

where V_{wsi} is the volume of water displaced by free imbibition of oil and V_{wt} represents the total volume of water displaced by free and forced imbibitions of oil. The Amott water index is expressed as:

$$I_w = \frac{V_{osi}}{V_{ot}} \tag{2}$$

where V_{osi} is the volume of oil displaced by spontaneous imbibition of water and V_{ot} denotes the total volume of oil displaced by spontaneous and/or forced imbibition of water. The Amott indices, I_o and I_w, range from 0 to 1. I_o and I_W values near 1 represent strongly oil- and strongly water-wet systems, respectively. The difference between I_w and I_o is known as the Amott–Harvey wettability index [3,32–35]:

$$I_{AH} = I_w - I_o \tag{3}$$

The I_{AH} index varies from -1 for strongly oil-wet to 1 for strongly water-wet cores. Systems with I_{AH} values between -0.3 and +0.3 are commonly considered intermediate-wet.

Donaldson et al. [36] proposed the USBM method to characterize the wettability of rocks based on the areas under forced displacement capillary pressure curves. The USBM index is given by

$$I_{USBM} = \log\left(\frac{A_1}{A_2}\right) \tag{4}$$

where A_1 and A_2 are the areas under the oil and water drive capillary pressure curves, respectively. The USBM index theoretically varies from $-\infty$ to $+\infty$. Usually, the USBM is mistakenly assumed to vary over the range of -1 to 1 and compared with other indices. Mirzaei–Paiaman [66] showed that in practice the lower and upper bounds of this index are not fully known. As a result, comparing USBM with other indices may cause erroneous interpretations due to dissimilar ranges of variation (other indices vary in the range of -1 to 1). Mirzaei–Paiaman [66] highlighted the bounded form of the USBM index denoted as USBM*, which varies between -1 (strongly oil-wet systems) and 1 (strongly water-wet systems), and suggested that it should replace the traditional form of the USBM index.

$$I_{USBM*} = \frac{A_1 - A_2}{A_1 + A_2} \tag{5}$$

Craig [38] introduced three rules of thumb based on relative permeability curves for the qualitative evaluation of wettability. In his approach, relative permeability is defined as the effective permeability of a fluid divided by oil permeability measured at interstitial water saturation. According to Craig's first rule, water relative permeability at residual oil saturation is generally less than 0.3 in water-wet systems, whereas its value is greater than 0.5 in oil-wet porous media. The second rule views a rock as water-wet, if water saturation at the intersection point of relative permeability curves is greater than 50%, otherwise oil-wet. According to the third rule in a water-wet system the value of interstitial water saturation is usually greater than 20 to 25% pore volume, whereas this is generally less than 15% pore volume (frequently less than 10%) for an oil-wet rock.

Ferreira et al. [39] presented another qualitative method to determine wettability from relative permeability curves, based on the concept of fractional flow Equation (6), called the normalized water fractional flow curve.

$$f_w = \frac{q_w}{q_t} = \frac{q_w}{q_w + q_o} = \frac{1}{1 + \frac{\mu_w k_{ro}}{\mu_o k_{rw}}} \tag{6}$$

where q_w is the water flow rate, q_o is the oil flow rate, and q_t is the total flow rate, μ_w is the water viscosity, μ_o is the oil viscosity, k_{ro} is the oil relative permeability, and k_{rw} is the water relative permeability. Ferreira et al. [39] assumed an equal viscosity for oil and water (viscosity ratio equal to 1) to eliminate the influence of the viscosity ratio on water fractional flow (f_w) and proposed changing Equation (6) into

$$f_w^{\mu_w = \mu_o} = \frac{1}{1 + \frac{k_{ro}}{k_{rw}}} \tag{7}$$

In the plot of normalized water fractional flow (based on Equation (7)) against normalized water saturation S_{wn} Equation (8), a sample with a curve below the 1:1 line is assumed to be water-wet, otherwise oil-wet. The normalized water saturation is given by

$$S_{wn} = \frac{S_w - S_{wc}}{1 - S_{or} - S_{wc}} \tag{8}$$

in which S_w is the water saturation, and S_{wc} is the interstitial water saturation.

Mirzaei–Paiaman [15] investigated the validity of Craig's rules of thumb and showed that while the third rule is generally unreliable, the first rule is suitable. Moreover, he showed that the second rule needed a modification. Mirzaei–Paiaman [15] pointed out that using 50% water saturation as a reference value in the Craig's second rule is unrealistic and defined a reference crossover saturation (RCS) as follows:

$$RCS = \frac{1}{2} + \frac{S_{wc} - S_{or}}{2} \tag{9}$$

where S_{wc} and S_{or} are both expressed as fractions.

According to the modified Craig's second rule established by Mirzaei–Paiaman [15], the crossover point of relative permeability curves lies to the right of RCS in water-wet rocks, while the crossover point is expected to be located at the left of the RCS in oil-wet systems. Following the above modification, Mirzaei–Paiaman [15] proposed a new wettability index by combining Craig's first rule and the modified Craig's second rule as follows:

$$I_L = \alpha\left(\frac{0.3 - k_{rw@ROS}}{0.3}\right) + \beta\left(\frac{0.5 - k_{rw@ROS}}{0.5}\right) + \frac{CS - RCS}{1 - S_{or} - S_{wc}} \tag{10}$$

where I_L is the Lak index and $k_{rw@ROS}$ is the water relative permeability at residual oil saturation. Recall that relative permeability is defined as the effective permeability divided by oil permeability at the interstitial water saturation. In Equation (10), CS is the crossover saturation in fraction, and α and β are constant coefficients determined based on $k_{rw@ROS}$ as follows:

$$\text{If} \begin{cases} k_{rw@ROS} < 0.3,\ then\ \alpha = 0.5,\ \beta = 0 \\ 0.3 \leq k_{rw@ROS} \leq 0.5,\ then\ \alpha = \beta = 0 \\ k_{rw@ROS} > 0.5,\ then\ \alpha = 0,\ \beta = 0.5 \end{cases} \tag{11}$$

Lak index varies from -1 (strongly oil-wet systems) to 1 (strongly water-wet systems).

In another study, Mirzaei–Paiaman et al. [13] showed that the areas below water and oil relative permeability curves could be used to estimate the average wettability as:

$$I_{ML} = \frac{A_o - A_w}{A_o + A_w} \tag{12}$$

where A_o and A_w are respectively the areas below oil and water relative permeability curves and I_{ML} is the modified Lak wettability index which varies from -1 in strongly oil-wet rocks to 1 in strongly water-wet samples. The near zero values of I_{ML} will indicate intermediate wettability.

3. Materials and Experiments

3.1. Plug Samples and Routine Tests

Nineteen core plug samples (with 1.5-inch diameter and 2-inch length) were collected from different depths of a single well in a carbonate reservoir located in the southwest of Iran. The American Petroleum Institute (API) standard of RP40 was employed to prepare the core plugs for routine and special core analysis (RCAL and SCAL) tests. The core plugs were first cleaned using toluene in the Soxhlet extractor in which clearness of the solvent was used as the indicator of a hydrocarbon-free sample. Plugs were then dried in the oven for 48 h. The cores were then cleaned using methanol to eliminate any existing salt crystals where clearness of the extracts in the presence of Silver Nitrate ($AgNO_3$) was adopted as the indicator of a salt-free sample. Consequently, the samples were again dried in the oven at 90 °C for 48 h. After that, the samples were cooled down in desiccators and used for the helium porosity and air permeability measurements.

The petrophysical characteristics (helium porosity and air permeability) of the rock samples are summarized in Table 1. Mirzaei–Paiaman et al. [67] proposed global hydraulic element-star (GHE*) as a graphical template to compare single-phase rock types from different sources (i.e., formations, reservoirs, fields, etc.). Their approach is based on the value of the reservoir quality index (*RQI*) of Leverett [68] that is used widely in the literature, e.g., by Xu and Torres-Verdin [69] and Mirzaei–Paiaman et al. [70]. The *RQI* is given by

$$RQI = 0.0314\sqrt{\frac{k}{\phi}} \tag{13}$$

where ϕ is the porosity in fraction, k is the permeability in millidarcy, and *RQI* is the reservoir quality index in microns.

The GHE* framework consists of a template comprising ten preset classes, as presented in Figure 1. In this figure, each line on the template corresponds to a given *RQI* value and describes the lower boundary of a prebuilt reference GHE* class. We used this technique to identify single-phase rock types.

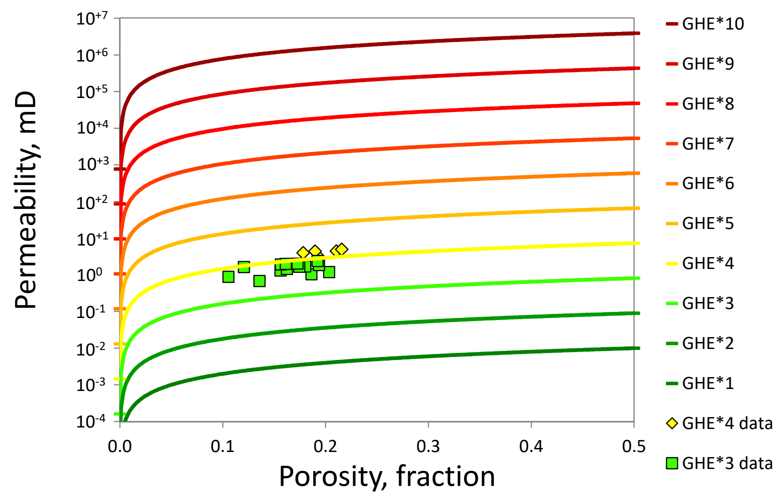

Figure 1. Permeability against porosity for the 19 carbonate rock samples as well as the ten preset classes shown by different GHE* curves. Each line on the template corresponds to a given *RQI* value and describes the lower boundary of a prebuilt reference GHE* class. As can be seen, the plug samples have been distributed in GHE* classes 3 and 4.

Table 1. Characteristics of the rock samples used in the experiments.

Plug No.	Depth (m)	Porosity (%)	Air Permeability (mD)	RQI (μm)	GHE* Class
1	2775.67	17.45	1.67	0.097	3
2	2776.08	19.38	2.98	0.123	4
3	2781.26	17.27	2.03	0.108	3
4	2799.48	18.98	4.39	0.151	4
5	2802.05	12.06	1.63	0.115	3
6	2804.33	10.57	0.88	0.091	3
7	2807.76	13.59	0.68	0.070	3
8	2824.54	19.38	1.86	0.097	3
9	2830.41	20.35	1.20	0.076	3
10	2834.6	16.23	1.45	0.094	3
11	2839.77	18.63	1.04	0.074	3
12	2843.74	16.14	1.99	0.110	3
13	2843.80	21.57	4.93	0.150	4
14	2846.00	15.66	1.92	0.110	3
15	2846.15	18.01	1.68	0.111	3
16	2850.66	19.22	2.39	0.149	4
17	2850.72	17.84	4.01	0.144	4
18	2851.23	21.05	4.44	0.091	3
19	2856.82	15.63	1.32	0.096	3

Table 1 includes the GHE* number and *RQI* value corresponding to each sample. As reported in Table 1, the plugs studied here belong to GHE* classes 3 and 4. This limited number of rock types is probably because porosity and permeability only span a factor of nearly two and seven, respectively, in the studied database. It is noteworthy to mention that the original GHE technique was presented by Corbett and Potter [71] based on the flow zone indicator (*FZI*) proposed by Amaefule et al. [72] as follows

$$FZI = \frac{0.0314\sqrt{\frac{k}{\phi}}}{\frac{\phi}{1-\phi}} \tag{14}$$

3.2. SCAL Tests and Fluids

Plugs were first saturated with a synthetic brine, i.e., a NaCl solution with salinity of 190 g/liter. They were then kept in the brine for at least ten days to reach ionic equilibrium conditions between the rock sample and the brine. Several pore volumes of brine were next injected at a constant pressure. The recorded data were used to calculate the absolute permeability of the samples by employing Darcy's law. After that, the primary drainage water-oil capillary pressure curve tests were conducted at 50 °C using the centrifuge method where dead crude displaced the brine at a series of centrifuge speeds until reaching the irreducible brine saturation. Next, the core plugs were kept in the crude oil at the reservoir temperature of 70 °C for almost two weeks to restore their native-state wettability. We flushed the cores twice with the crude oil during the aging process to enhance a uniform wettability in the samples. To alleviate the injectivity issues and possible permeability impairment phenomena that were likely in the next-step flooding tests, the dead reservoir oil was replaced by a synthetic oil (n-Decane). We injected decalin as a buffer fluid between synthetic oil and crude oil to prevent any potential asphaltene precipitation and deposition. Consequently, the unsteady-state brine displacing oil tests were conducted at room temperature and continued until no more oil was produced. The collected data were used to calculate the relative permeability curves using the method of Jones and Roszelle [73].

After the relative permeability tests, the core plugs were centrifuged at room temperature where synthetic oil displaced water to attain irreducible brine saturation. Afterwards, spontaneous and forced displacement processes were carried out. The volume of brine freely imbibed into the plug was measured in the Amott cell, followed by brine displacing oil centrifugal displacement at several rotational speeds to reach the residual oil saturation where forced displacement capillary pressure curves were also determined. Then, the volume of oil freely imbibed into the plug was measured in the Amott cell, followed by oil displacing brine centrifugal displacement at several rotational speeds to reach irreducible water saturations where the corresponding forced displacement capillary pressure curves were also determined. Measurements on three samples (plugs no. 8, 16, and 18) had questionable results that were rejected after quality control. The properties of the fluids used are shown in Table 2.

Table 2. Fluid characteristics used in the primary drainage and imbibition/secondary drainage experiments.

Test \ Property	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

4. Results and Discussion

Figure 2 shows the measured forced displacement capillary pressure curves. In this figure, the positive curves correspond to secondary drainage process where the negative ones represent primary imbibition displacement. The area below each curve was determined to calculate the USBM and USBM* indices using Equations (4) and (5), respectively. The Amott index of oil, Equation (1), and water, Equation (2) as well as the Amott–Harvey index Equation (3) were also calculated using the variations in saturation corresponding to the spontaneous and forced displacements.

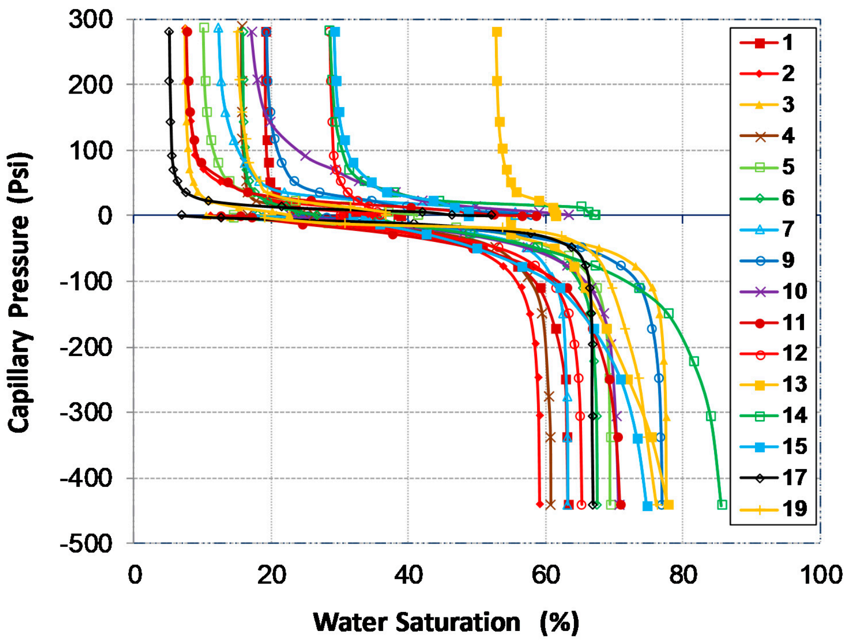

Figure 2. The measured forced displacement capillary pressure curves for 16 samples studied here.

Table 3 summarizes the calculated values of the Amott, Amott–Harvey, USBM, and USBM* indices. As indicated in Table 3, for three samples (8, 16, and 18) the capillary pressure curves were not available, for which I_w, I_o, I_{AH}, I_{USBM} and I_{USBM^*} were not reported. For the remaining 16 samples, we found general agreement among these five indices. Results showed oil-wet conditions for 14 samples and intermediate-wet conditions for samples 7 and 10.

Table 3. The calculated values of the Amott, Amott–Harvey, USBM, and USBM* indices based on fluid displacement through imbibition and/or drainage processes.

Plug No.	Amott Water Index I_w	Amott Oil Index I_O	Amott–Harvey Index I_{AH}	USBM Index I_{USBM}	USBM* Index I_{USBM^*}
1	0.09	0.55	−0.46	−0.87	−0.76
2	0.07	0.47	−0.40	−0.23	−0.26
3	0.04	0.78	−0.74	−0.76	−0.70
4	0.02	0.76	−0.74	−0.82	−0.74
5	0.07	0.47	−0.40	−0.26	−0.29
6	0.04	0.79	−0.75	−0.81	−0.73
7	0.10	0.15	−0.05	0.08	0.09
8	N.A.	N.A.	N.A.	N.A.	N.A.
9	0.07	0.33	−0.26	−0.29	−0.32
10	0.10	0.14	−0.04	0.03	0.03
11	0.08	0.20	−0.12	−0.42	−0.45
12	0.04	0.80	−0.76	−0.82	−0.74
13	0.08	0.65	−0.57	−0.95	−0.80
14	0.06	0.32	−0.26	−0.52	−0.54
15	0.06	0.57	−0.51	−0.68	−0.64
16	N.A.	N.A.	N.A.	N.A.	N.A.
17	0.03	0.24	−0.21	−0.21	−0.24
18	N.A.	N.A.	N.A.	N.A.	N.A.
19	0.07	0.65	−0.58	−0.56	−0.57

Figure 3 shows the oil and water relative permeability curves measured on the 19 core samples. Although the oil relative permeability curves are similar in terms of shape (upward curvature), the water relative permeability curves are diverse representing a wide range of behaviors. Figure 4 shows the normalized water fractional flow data, Equation (7), against the normalized water saturation, Equation (8). As can be seen, most data points are above the 1:1 line, which indicates oil-wetness of the samples.

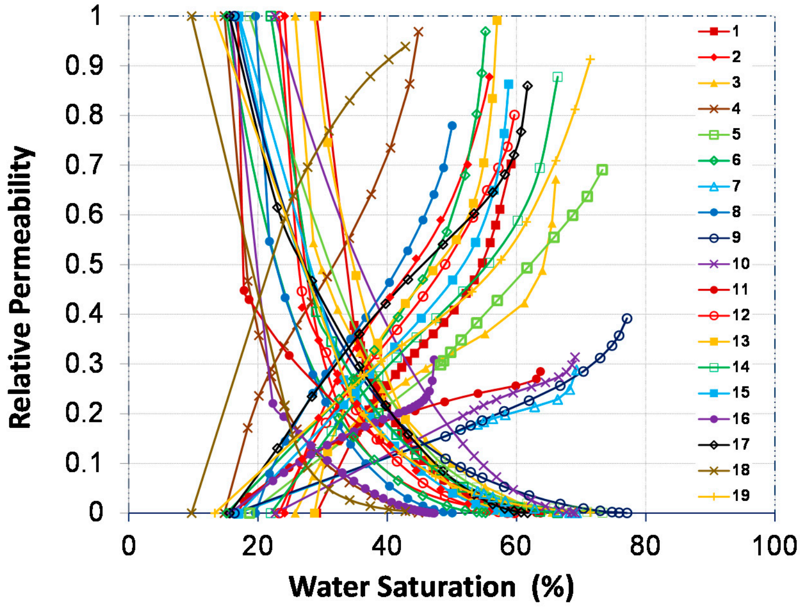

Figure 3. The oil and water relative permeability curves measured on 19 carbonate rock samples studied here.

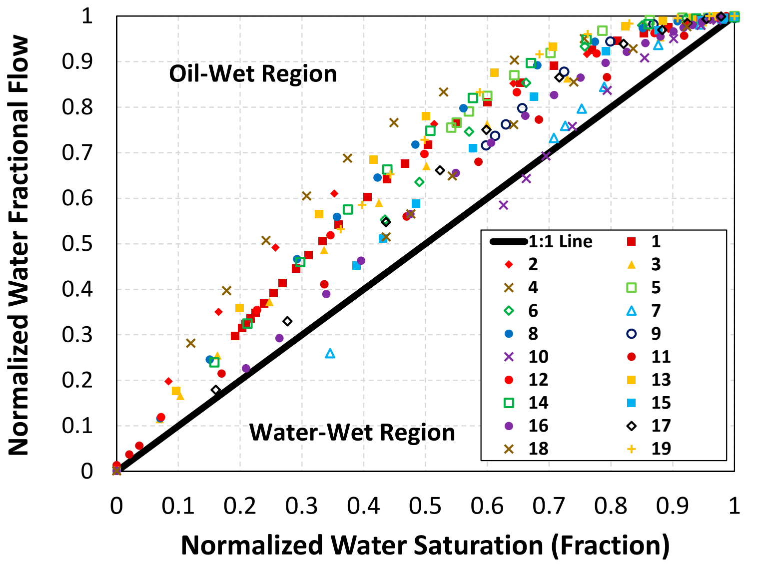

Figure 4. Normalized water fractional flow, Equation (7), against normalized water saturation, Equation (8), for all the 19 samples studied here. The solid black line indicates the 1:1 line.

The relative permeability measurements were used to evaluate Craig's rules of thumb and the modified Craig's second rule, plot the normalized water fractional flow curves, and calculate the values of Lak and modified Lak indices (Table 4). As Table 4 indicates, the results of Craig's second rule and those of the modified Craig's second rule are in agreement for all samples except samples 7 and 10. For these two samples other indicators show water-wet conditions. While Craig's second rule characterizes these samples as oil-wet, the modified Craig's second rule labels them as water-wet. Furthermore, Craig's third rule also provided results inconsistent with the others. Although Craig's third rule predicted water-wet conditions, other indices recommend oil-wet. Such inconsistencies have been previously reported by Mirzaei–Paiaman [15]. Since the results of Craig's second and third rules are inconsistent with those of other approaches, we excluded them from further analyses.

Table 4. Results of wettability evaluation by the relative permeability-based methods.

Sample	k_{rw} at S_{or} *	CS (%)	S_{wc}(%)	S_{or}(%)	RCS (%)	Qualitative Methods					Quantitative Methods	
						Craig's First Rule	Craig's Second Rule	Craig's Third Rule	Modified Craig's Second Rule	Normalized Water Fractional Flow Curve	I_L	I_{ML}
1	0.70	38.9	29.1	40.9	44.1	OW	OW	WW	OW	OW	−0.37	−0.21
2	0.88	31.3	24.1	44.2	40.0	OW	OW	WW	OW	OW	−0.61	−0.37
3	0.67	41.0	25.8	34.0	45.9	OW	OW	WW	OW	OW	−0.29	−0.14
4	0.97	21.7	14.8	55.2	29.8	OW	OW	OW	OW	OW	−0.74	−0.41
5	0.69	40.8	18.7	26.7	46.0	OW	OW	-	OW	OW	−0.29	−0.06
6	0.97	31.8	15.2	44.8	35.2	OW	OW	-	OW	OW	−0.55	−0.11
7	0.29	46.5	16.9	30.7	43.1	WW	OW	-	WW	WW	0.08	0.25
8	0.78	29.2	19.6	50.0	34.8	OW	OW	-	OW	OW	−0.46	−0.27
9	0.39	45.8	16.4	22.9	46.7	-	OW	-	OW	OW	−0.02	0.11
10	0.31	49.3	22.7	31.0	45.9	-	OW	WW	WW	WW	0.07	0.17
11	0.28	36.6	16.9	36.3	40.3	WW	OW	-	OW	OW	−0.05	0.00
12	0.80	33.7	23.3	40.3	41.5	OW	OW	WW	OW	OW	−0.51	−0.34
13	0.99	38.3	28.7	43.0	42.9	OW	OW	WW	OW	OW	−0.65	−0.20
14	0.88	36.4	22.0	33.6	44.2	OW	OW	WW	OW	OW	−0.55	−0.27
15	0.86	34.6	17.1	41.2	37.9	OW	OW	-	OW	OW	−0.44	−0.02
16	0.31	29.1	15.7	52.7	31.5	-	OW	-	OW	OW	−0.08	0.09
17	0.86	34.0	15.6	38.3	38.7	OW	OW	-	OW	OW	−0.46	−0.12
18	0.94	20.2	9.7	57.2	26.3	OW	OW	OW	OW	OW	−0.62	−0.33
19	0.91	34.0	13.3	28.6	42.4	OW	OW	OW	OW	OW	−0.56	−0.15

* k_{rw}: water relative permeability; S_{or}: residual oil saturation; *CS*: crossover saturation; S_{wc}: interstitial water saturation; *RCS*: reference crossover saturation; I_L: Lak wettability index; I_{ML}: modified Lak wettability index; OW: oil-wet; WW: water-wet.

Results of the relative permeability-based methods implied that the qualitative and quantitative indices consistently predicted oil-wet conditions for 14 samples (all samples excluding 7, 9, 10, 11, and 16). Such methods indicated almost water-wet conditions for samples 7 and 10. For samples 9, 11, and 16 there was no agreement among the different methods. For samples 9 and 16, while qualitative methods characterized oil-wet rocks, quantitative indices showed intermediate-wet conditions. For sample 11, while Craig's first rule indicated that the rock sample should be water-wet, the modified Craig's second rule and normalized water fractional flow curve recommended oil-wet. For this sample the Lak and modified Lak indices represented intermediate-wet rock. Comparing the results of the relative permeability-based methods with those of the Amott, Amott–Harvey, USBM, and USBM* techniques showed generally good agreements among these approaches, despite their difference in terms of concepts and methodologies.

We also investigated possible correlations and trends among the wettability indices. Cross-plots of different wettability indices studied here are shown in Figure 5 in which the dashed line represents the 1:1 line and the solid red line denotes the linear equation fitted to the data. As mentioned earlier, while USBM is an unbounded index it is usually mistakenly assumed to vary over the range of −1 to 1 and compared with other indices. Comparison between USBM and other indices may cause erroneous interpretations due to dissimilar ranges of variation (other indices vary in the range of −1 to 1). In this study, we therefore used USBM* as a replacement of the traditional USBM index [66] in the comparative analysis. USBM* varies over the range of −1 to 1, similar to other indices. Although the trends are similar (as one index increases another one increases as well), the correlation coefficient R^2 varies from one plot to another. The highest correlation coefficient values belong to the USBM*–Amott–Harvey (see Figure 5a) and Lak–Modified Lak (see Figure 5b) plots. The high R^2 value between the Lak and modified Lak indices might be because these two methods apply the same concepts based on relative permeability measurements. The relatively high correlation coefficient between Amott–Harvey and USBM* indices (R^2 = 0.70), given that they are based on different concepts, might be due to lack of spatial heterogeneity in the database studied here. Recall that the carbonate rock samples were collected along a well from a single carbonate reservoir. Analyzing samples from different geologic formations might lead to higher level of heterogeneity and accordingly lower correlation coefficients. The modified Lak index, I_{ML}, was correlated to the USBM* and Amott–Harvey indices with R^2 = 0.44 (Figure 5c,f). However, the Lak index, I_L, was slightly more correlated to I_{USBM*} with R^2 = 0.48 and I_{AH} with R^2 = 0.52 (Figure 5d,e).

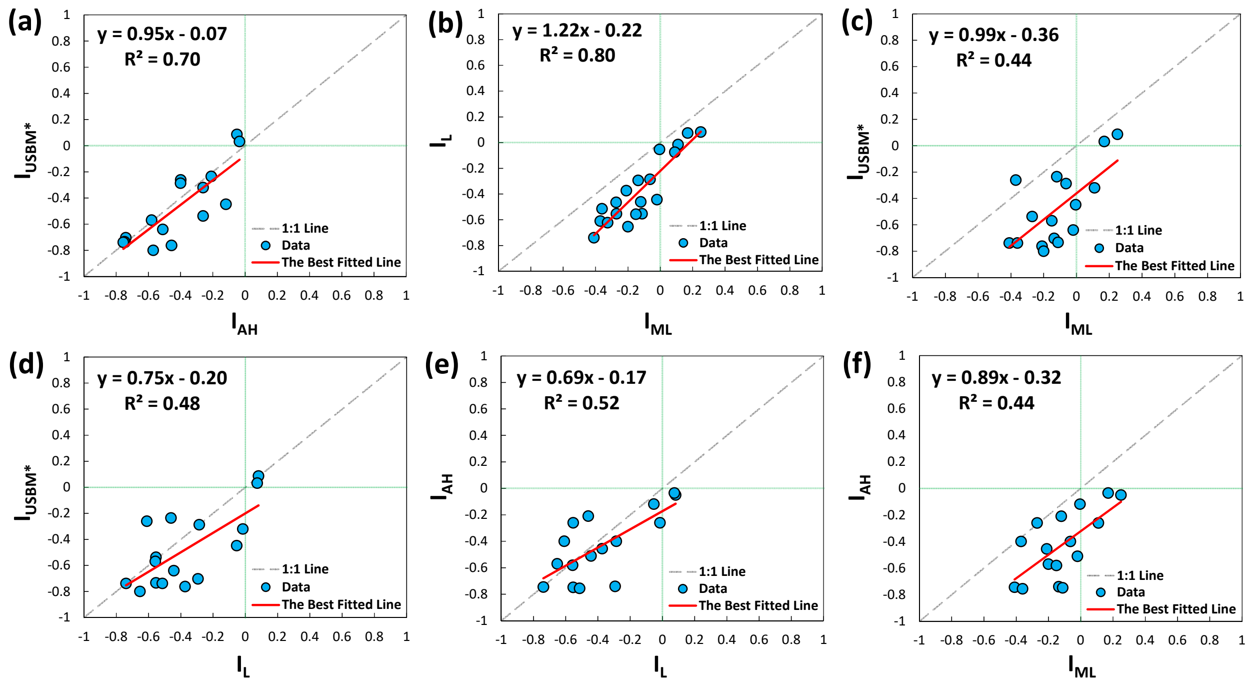

Figure 5. Correlations among different wettability indices calculated on core samples studied here. (**a**) USBM* vs. Amott–Harvey, (**b**) Lak vs. modified Lak, (**c**) USBM* vs. modified Lak, (**d**) USBM* vs. Lak, (**e**) Amott–Harvey vs. Lak, and (**f**) Amott–Harvey vs. modified Lak.

In the literature, there exist various approaches for rock typing. For recent reviews see [74,75]. To explore the trends among wettability indices and rock quality indicators, we calculated *RQI* and *FZI* values based on Equations (13) and (14), respectively. The Winland R_{35} [76], as one of the widely used rock quality indicators, was also determined from the porosity and permeability measurements as follows

$$\log(R_{35}) = 0.732 + 0.588 \log k - 0.864 \log(100\phi) \tag{15}$$

where R_{35} is in microns. Figure 6 displays the quantitative wettability indices I_{AH} (Amott–Harvey), I_{USBM*} (USBM*), I_L (Lak), and I_{ML} (modified Lak) against the reservoir quality indicators *FZI*, *RQI*, and Winland R_{35}. In general, as rock quality indicators increase (or rock quality improves), the wettability indices decrease, meaning that the rocks become more oil-wet. Results showed that the USBM* and Amott–Harvey indices, I_{USBM*} and I_{AH}, were weakly correlated to the rock quality indicators (0.03 < R^2 < 0.2). Although the Lak and modified Lak indices, I_L and I_{ML}, were intermediately correlated to the rock quality indicators *RQI* and Winland R_{35} (0.41 < R^2 < 0.50), they were weakly correlated to *FZI* (R^2 = 0.27 for I_L and 0.14 for I_{ML}). As shown by Mirzaei–Paiaman et al. [74], while *FZI* is a function of grain diameter, the value of *RQI* is mainly controlled by pore-throats and their sizes. Winland R_{35} is also a function of pore-throat radii [76]. Since the Lak and modified

Lak indices are based on the relative permeability measurements, they are strongly affected by wetting characteristics of larger pore throats, which control fluid flow through rocks. The network of larger pore throats also controls rock quality. However, the USBM* and Amott–Harvey indices take into account the effect of both small and large pore throats. This could be the reason for relatively high correlations between Lak and modified Lak indices and rock quality indicators *RQI* and Winland R_{35}. However, the number of samples used in this study is limited to 19 core plugs and the dataset is rather homogeneous (samples were collected along one well in a carbonate reservoir). Adding more samples from different formations may result in more scatter in the data. Further investigations are required to address the trend between wettability indices and rock quality indicators.

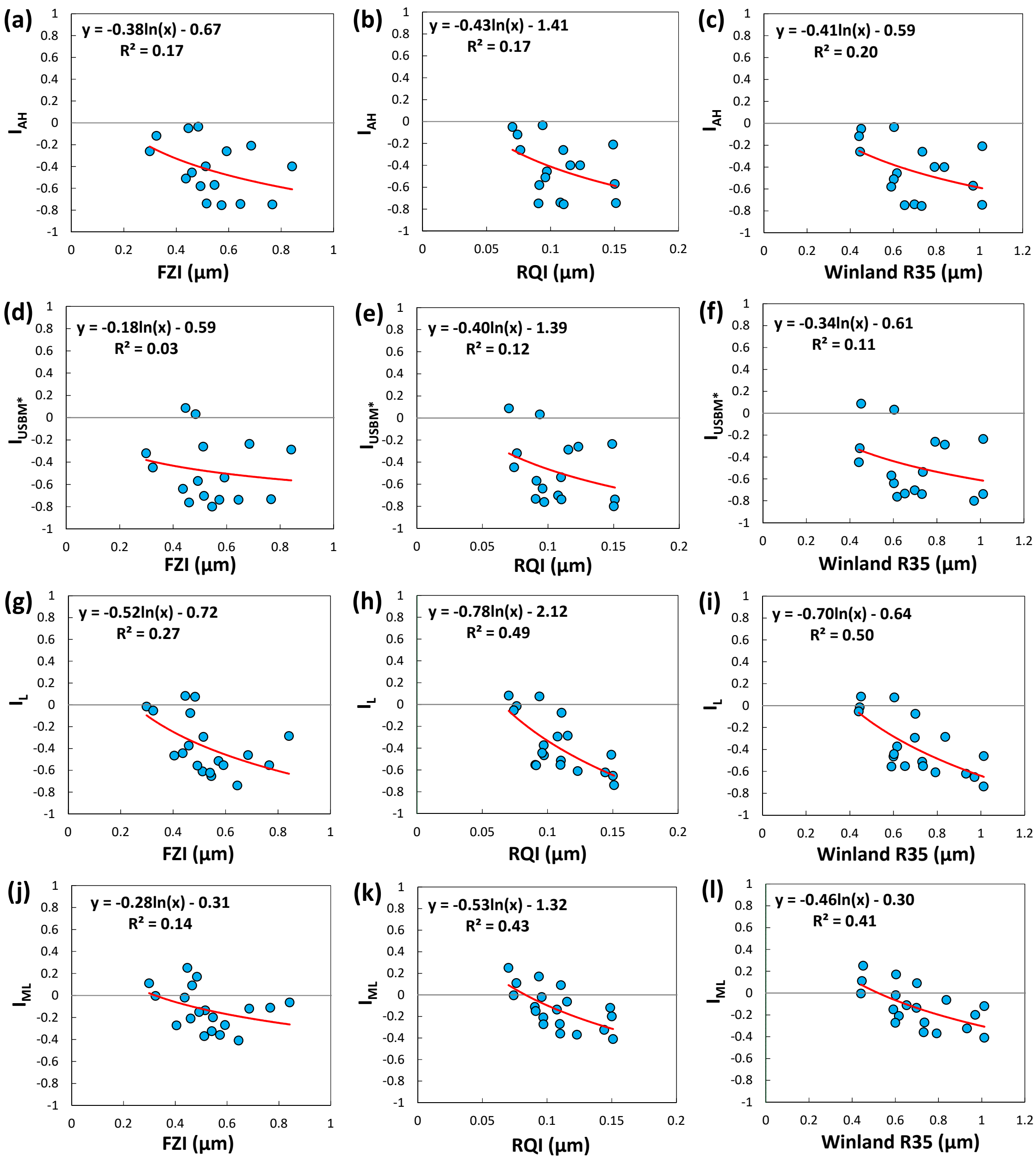

Figure 6. Different wettability indices versus rock quality indicators for the carbonate rock samples used in this study. (**a**) Amott-Harvey vs. *FZI*, (**b**) Amott-Harvey vs. *RQI*, (**c**) Amott-Harvey vs. Winland R_{35}, (**d**) USBM* vs. *FZI*, (**e**) USBM* vs. *RQI*, (**f**) USBM* vs. Winland R_{35}, (**g**) Lak vs. *FZI*, (**h**) Lak vs. *RQI*, (**i**) Lak vs. Winland R_{35}, (**j**) modified Lak vs. *FZI*, (**k**) modified Lak vs. *RQI*, (**l**) modified Lak vs. Winland R_{35}.

5. Conclusions

In this study, a set of capillary pressure and relative permeability curves measured on 19 carbonate rock samples was used to analyze and compare different wettability indices, such as Amott, Amott–Harvey, and USBM* as well as the relative permeability-based wettability measurement methods of Craig's rules of thumb, modified Craig's second rule, normalized water fractional flow, Lak, and modified Lak. The following conclusions can be drawn from this study based on 19 core plugs from a single well in a carbonate reservoir:

- Generally speaking, good agreement was obtained between the relative permeability-based methods and Amott, Amott–Harvey, and USBM* techniques in identifying the wetness of carbonate samples, despite such methods being based on different concepts and physics. Thus, it is convenient to use relative permeability-based methods when the required data for the Amott–Harvey and USBM* methods are not available.
- There was a good correlation between the USBM* and the Amott–Harvey methods as well as between the Lak and the modified Lak approaches. Intermediate correlations were observed among the other methods.
- Comparing the wettability indices with rock quality indicators showed that as *FZI*, *RQI*, and Winland R_{35} increased (or rock quality improved), samples became more oil-wet.
- Rock quality indices *RQI* and Winland R_{35} that are mainly a function of pore throats and their sizes were correlated with wettability indices higher than the *FZI*.
- The Lak and modified Lak indices, as two quantitative relative permeability-based wettability techniques, provided higher correlations with rock quality indicators than the Amott–Harvey and USBM* indices. Those wettability indices strongly affected by wetting characteristics of larger pore throats were higher correlated to rock quality indicators than indices taking into account the effect of both small and large pore throats.

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