Review of the Effect of Temperature on Oil-Water Relative Permeability in Porous Rocks of Oil Reservoirs

By

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Abstract:

Thermal methods of heavy oil recovery involve multiphase flow at high temperatures. Numerical simulation studies of such processes require accounting for changes in the multi-phase flow behavior of the rock-fluid system with increasing temperature. Although the effect of temperature on two-phase relative permeability has been studied for more than five decades, it remains an unresolved issue. Experimental results that frequently contradict each other are still being reported and the issue remains a matter of debate. The purpose of this review is to critically examine the reported results and explore the possible reasons for contradictory results. We have examined the reported results of more frequently cited papers from past five decades and attempted to rationalize the disagreements in findings.

There appear to be three main reasons for the lack of consensus in experimentally observed results. The measurements of relative permeability at high temperature are complex and the reported results often include experimental artifacts. Secondly, meaningful relative permeability measurements require that capillary forces control the fluid distribution within the pore space, but this condition is difficult to ensure in viscous oil systems. The third reason is that the impact of temperature is not same in all rock-fluid systems, it depends on how the wettability, interfacial tension and the pore geometry changes with temperature.

It becomes apparent that it is not advisable to generalize the effect of temperature on relative permeability from previous studies without having a good understanding of how the underlying parameters that can influence the relative permeability are changing with temperature. The relative permeability of a specific petroleum reservoir may (or may not) vary with temperature.

1. INTRODUCTION

Thermal recovery of heavy oil and bitumen involves two-phase and three-phase flow of oil, water and gas at high temperatures in oil bearing porous formations. Modeling of such processes requires accounting for changes in the multiphase flow properties of reservoir rocks resulting from the increase in temperature. Heating the rock from original reservoir temperature to the high temperatures, which can exceed 300 ^{o}C in steam injection and much higher in in-situ combustion processes [1], brings about changes in rock-fluid properties that can have a large impact on the flow behavior. The viscosity of heavy oil decreases by several orders of magnitude [2-7] and this by itself can significantly change the flow characteristics [8-11]. Furthermore, such large increase in temperature can also change other rock-fluid properties, including wettability [4, 12-20], interfacial tension [7, 14, 16, 21-25] and pore geometry.

Multiphase flow in porous media is complicated due to contributions of many factors, such as, complex pore geometry, the rock wettability, properties of different phases, capillary pressure, pore and throat size distributions and compressibility of the porous medium. The commonly used mathematical description of multiphase flow in porous media is based on the extension of the Darcy's equation to multiphase flow [26] by introducing the concept of effective permeability for each phase that varies with saturations of different phases. Under two-phase flow conditions, the effective permeability for each fluid phase becomes a function of its own saturation [27-29]. This dependence of effective permeability on saturation is usually described by defining a relative permeability, which represents the ratio of the effective permeability to a base permeability, which is often the absolute permeability of the medium [28-30]. The advantage of using relative permeability to describe the variation with saturation is that it separates the changes in absolute permeability from the effects of fluid saturation. It allows one to account for the effect of permeability heterogeneity in the reservoir by assuming that the same relative permeability curve applies at different values of the absolute permeability. In most reservoir engineering flow studies, the relative permeability is one of the most crucial parameters [31].

The knowledge of two-phase water/oil relative permeability is needed to predict the production rate, breakthrough time and the ultimate oil recovery in processes involving displacement of oil by water [32, 33]. The relative permeability also affects the pressure response and velocity profile of fluids flowing through the porous rock in such displacements. The relative permeability varies from one oil reservoir to another and it may even be different for two core plugs with the same geometry, geology, lithology, composition, and physical properties (porosity and permeability) but with different pore size distributions [29, 34]. In the same rock, the relative permeability can change with the type of fluids saturating the pores [29, 32]. Accordingly, there is always some uncertainty when a given set of relative permeability data, which was measured using the best available technique on a core sample from a specific reservoir using native fluids, is used for analysis of other similar reservoirs [29, 30]. Actually, uncertainty remains, to some extent, even in the analysis of the reservoir from which the core sample was obtained, due to the possibility of changes in the behavior in different parts of the formation.

Numerous studies have been reported in the petroleum literature on relative permeability properties of different types of porous media and on the effects of rock-fluid characteristics that affect the flow behavior [29, 35, 36]. The effect of temperature on relative permeability curves has received significant attention since 1950’s [6]. There are published reports that contradict each other on the temperature impact on two-phase relative permeability for various systems [2-4, 6, 7, 12, 25]. In addition, numerous studies have attempted over the years to present the effect of temperature on relative permeability by proposing some useful relative permeability models even for a particular system [5, 25, 37-42]. The objective of this study is to critically review such published articles [2-4, 6-8, 12, 13, 15-17, 19, 21, 24, 25, 38, 40-53] on the effect of temperature on two-phase relative permeability and distill useful information and insights into the changes in behavior that occur as a function of the temperature. This involves careful examination of the effect of temperature on characteristics of relative permeability curves for different porous media types and various fluid types in a wide range of temperature and pressure. This extensive survey endeavors to clarify how the contribution of various variables including wettability alteration, viscosity ratio, capillary end effect, saturation history, data interpretation method, type of oil and porous medium, and the employed experimental procedure, as well as human errors and experimental artifacts could have led to contradictory findings. In this review, the most cited publications since 1956 are examined and the effect of temperature on different attributes of the relative permeability curves are extracted and analyzed.

2. RELATIVE PERMEABILITY CONCEPT

When two immiscible fluids flow simultaneously through a reservoir rock, the conductivity of the rock to each fluid depends not only on the permeability of the rock but also on the relative amount of each fluid present in the pore space. In other words, the effective permeability to each fluid depends on the absolute permeability of the rock and the fraction of the pore space occupied by that fluid, which is called the fluid saturation. The relative permeability is defined as the effective permeability divided by a base permeability, which is often the absolute permeability of the medium, as shown in Eq. (1) below.

$$k_{ri}\left(S_i\right)=k_{ei}\left(S_i\right)/k_{abs} \qquad (1)$$

Where k_{ri} is the relative permeability to fluid *i*, when its saturation is S_i, $k_{ei}\left(S_i\right)$ is the effective permeability to fluid *i* at the same saturation, k_{abs} is the absolute permeability and *i* denotes either oil or water. Very often, under two-phase flow conditions in oil reservoirs, the relative permeability to each fluid is a function only of the saturation of that fluid and it is independent of other flow parameters. The rationale for treating the relative permeability to be a determinable function of saturation is based on the concept that the two immiscible fluids flow largely in parallel but separate pore networks and that the fluid distribution within the pores is controlled primarily by capillary forces [27, 29]. It is generally true that the capillary forces acting on the fluids under typical reservoir flow conditions are several orders of magnitude larger than viscous and inertial forces [54, 55]. Therefore, the distribution of the two immiscible fluids is often controlled by the capillary forces [54, 55]. This dominance of surface forces favors the fluid distribution that minimizes the free energy of solid-fluid and fluid-fluid interfaces. Consequently, the wetting phase and the non-wetting phase tend to follow predictable pore occupancy rules and the distribution of phases within the pore space is theoretically predictable at any specific saturation [29, 56]. The relative permeability to each phase depends on which portion of the available pore space it occupies and this, coupled with the capillarity controlled pore occupancy rules, makes the relative permeability a determinable function of saturation. It should be understood that any deviation from the capillarity controlled fluid distribution would result in the relative permeability becoming dependent on other factors.

For quantifying the effect of various rock-fluid characteristics on two-phase oil/water relative permeability curves, the two curves can be characterized with six different features. These parameters include the irreducible water saturation, the residual oil saturation, oil relative permeability at the irreducible water saturation, water relative permeability at the residual oil saturation and the shapes of the two curves (which can often be described by the degree of curvature involved). Before discussing the effect of temperature on these six parameters of the relative permeability curves, the significance of each of them is explained below.

2.1. Irreducible water and residual oil saturation

The irreducible water saturation is simply defined as the lowest water saturation which can be achieved by oil flooding a water saturated core plug [29]. At irreducible water saturation, the relative permeability to water becomes 'practically' zero; as a result, no further water can be displaced by continued injection of oil [29, 30, 36]. Similarly, the residual oil saturation is the lowest oil saturation obtained by water flooding an oil-saturated porous medium [29]. Therefore, the oil relative permeability during the water flooding declines gradually and becomes 'practically' zero at the residual oil saturation [29, 30]. The word 'practically' is used here to emphasize the fact that in experimental measurements of these parameters the value may not reach the mathematical zero point but becomes small enough to be considered negligible [8, 16, 51].

2.2. Endpoint relative permeability to oil and water

The endpoint relative permeability to water is the highest value of water relative permeability and occurs at the residual oil saturation [29]. At this point, only water is able to flow in the two-phase system [29, 56]. In water-wet systems, the residual oil saturation will be present as isolated oil droplets or blobs of varying size [29, 56]. This discontinuous saturation of oil remains trapped by capillary forces [56]. In oil-wet systems, the residual oil saturation can remain continuous as thin wetting film on pore surfaces but it is practically immobile [56-59].

The endpoint relative permeability to oil occurs at the irreducible water saturation, i.e. when only oil is able to flow in the two phase system [36]. In water-wet systems the irreducible water saturation may remain continuous in the form of a thin wetting film on pore surfaces but its mobility is practically zero [57-60].

2.3. Shapes of oil and water relative permeability curves

The relative permeability of each phase is zero at its residual saturation and becomes highest when its saturation reaches the maximum possible value [29, 30, 56]. In between these two limits, the relative permeability is expected to increase monotonically with increasing phase saturation, since more flow channels become available for its flow as it occupies more of the total pore space [27]. The manner in which the relative permeability increases with increasing saturation (i.e. the shape of relative permeability curve) depends on several factors including the pore size distribution, pore connectivity, wettability and saturation history [27, 29, 56].

2.4. Effect of Temperature

Theoretically, the relative permeability of each phase depends on which portion of the total pore space each fluid occupies and the conductivity of that portion of the pore space. Therefore, the increase in temperature can affect the relative permeability only two ways: 1) it changes the conductivity of the occupied pore space by altering the pore geometry or 2) it re-distributes the two fluids within the pore space by changing the capillary and other forces that control the fluid distribution. Although, it is possible that a large increase in the temperature can generate in-situ thermal stresses that may significantly affect the pore geometry, the laboratory measurements of relative permeability are generally conducted under conditions that minimize this possibility. Hence, the observed effects of temperature on relative permeability arise mostly from re-distribution of fluids due to altered balance between capillary and viscous forces. Consequently, understanding the effect of temperature on relative permeability requires understanding how the forces that control fluid distribution within the pore space change with temperature. An additional factor that needs to be considered is the impact of differences in the experimental protocol used for evaluating the effect of temperature on relative permeability. These differences include the selection of experimental technique, e.g. steady-state versus displacement method, the differences in the experimental materials and conditions, and the way in which the selected measurement technique was implemented.

In this paper, we first review the commonly used methods for measuring the relative permeability and then, in Section 4, we examine the impact of the experimental conditions and materials used in various reported studies. In Section 5, we review the changes in rock-fluid properties with temperature that can affect the relative permeability. Finally, in section 6, we review the reported effects of temperature on oil-water relative permeability curves by examining how the six parameters of oil-water relative permeability curves change with temperature and attempt to explain the experimental observations in terms of the materials and methodology used in different studies. Section 7 lists the conclusions of this study.

3. METHODS FOR DETERMINATION OF RELATIVE PERMEABILITY CURVES

The two-phase relative permeability of a porous medium can be evaluated using several techniques, including different experimental measurement techniques, methods based on mathematical modeling of two-phase flow, empirical correlations, and by the analogy method [27, 29, 30]. The laboratory methods include the steady-state and unsteady-state flow tests, the centrifuge method and the use of capillary pressure measurements to estimate relative permeability [27, 29, 30]. The focus in this paper is on the laboratory measurements.

The measurement of relative permeability generally involves the use of a small sample of the porous medium and creation of one-dimensional two-phase flow in the sample, during which the conductivity of the medium to each phase can be inferred from measured and imposed test parameters. Four distinct experimental approaches have been mentioned in the literature and are considered reasonably reliable.

3.1. Steady-state approach

The most direct, and for that reason also the most reliable, experimental method is the steady-state method [31, 61]. It involves injection of a fixed ratio of oil and water (or any two immiscible phases) into the porous medium sample at a constant rate to generate one-dimensional flow until the pressure drop across the sample and the fractional flow coming out of the sample become stable [29, 36, 62]. Although the saturation profile within the sample and the pressure drop across its length change in the early stage of the test, it is expected that eventually the saturation profile and the pressure will become steady and the produced fractional flow will be identical to the injected one [6, 7, 18, 24, 29, 36, 61-63]. To obtain the complete relative permeability curve, usually between 5 and 10 different ratios of water/oil flow rates are employed [24, 63, 64]. Darcy's law is applied to estimate the effective permeability of each phase using the measured pressure drop across the core and imposed flow rates [29, 48, 62].

Numerous techniques have been reported to establish an uniform saturation profile, since the capillary end effect, which causes the wetting-phase saturation to be high near the outlet end, is always a big concern in such measurements [29]. Moreover, to obtain reliable results, the average water and oil saturations have to be determined accurately, either by material balance or using an in-situ measurement technique [36]. The reported steady-state relative permeability techniques include: Penn-State method [65-67], Single-Sample dynamic method [68-70], Stationary fluid method [71], Hassler method [72], Hafford method [70], and Dispersed feed method [70]. Among these methods, the Hassler method has been used more often, although it is accepted that this technique only works properly when the sample is strongly wetted by one of the fluids [29]. Experimental difficulties have been reported in using the Hassler procedure under conditions of intermediate wettability[73, 74]. The general comments on pros and cons of different method for measuring relative permeability are summarized in Table 1.

Table 1. General comments on laboratory relative permeability measurement methods [30].

Steady-State approach	• Full saturation range can be covered • Relative permeability down to 10^{-3} • Lower accuracy near endpoint saturations • Very time consuming and expensive because of the required pressure and saturation stabilization for each reading.
Unsteady-State approach	• Fast and less expensive, hence widely used • Relative permeability down to 10^{-3} • Representative of the dynamic reservoir situation • A part of the saturation range not directly accessible
Centrifuge approach	• Relative permeability only of displaced phase • Relative permeability down to 10^{-6} • Better estimation of endpoint region

3.2. Unsteady-state approach

The unsteady-state approach is a displacement method in which an immiscible displacing fluid is injected at constant rate into a core sample, initially containing the highest possible saturation of the displaced fluid (under two-phase conditions), and the transient behavior of pressure drop across the length of the core and the volumes of produced phases are recorded periodically [31, 36]. The main advantage of this method is that it is less time-consuming [30]. The relative permeability characteristics are inferred from the recorded production and pressure drop history of the displacement test [31]. This requires a more complex calculation procedure than the steady-state method [29]. Further comments about the pros and cons of unsteady-state approach are included in Table 1.

3.3. Capillary pressure approach

The capillary pressure approach relates the relative permeability curves to measured capillary pressure-saturation relationship [29]. The rationale behind it is that, when a porous medium exhibits a clear wetting preference for one of the two fluid phases, the distribution of the two fluids within the pore space is governed by clear-cut pore occupancy rules that result in the wetting fluid occupying the smallest available pores. Since both the drainage capillary pressure and the relative permeability at any given wetting phase saturation are controlled by the radius of the smallest pore invaded by the non-wetting phase, it is logical that there is a relationship between them. Several scholars [75-79] have developed analytical equations for estimating the non-wetting and wetting phase relative permeability from capillary pressure data.

3.4. Centrifuge approach

Centrifuge method for relative permeability is similar to centrifuge method for measuring capillary pressure except that now the volume of displaced fluid produced is recorded against time after each step change in the rotational speed of the centrifuge. The fluid production is similar to the unsteady state displacement with specified inlet and outlet pressures [80, 81] and a computational method to obtain the relative permeability is available [81]. This technique does not suffer from viscous fingering problems, which sometimes happens during unsteady-state tests [29, 61]. Also, the centrifuge relative permeability test can be conducted substantially faster than the steady-state method [29]. Table 1 includes some other comments on the pros and cons of this method.

4. IMPACT OF EXPERIMENTAL CONDITIONS ON OBSERVED EFFECT OF TEMPERATURE ON RELATIVE PERMEABILITY

One of the important factors controlling the relative permeability is the wettability state of porous medium [29, 56]. The properties of the two fluid phases used will affect the contact angle, wettability, interfacial tension, and capillary pressure. Many other factors can also affect the relative permeability to varying degrees. Some researchers [2, 15, 17, 20, 22, 25, 42, 45, 50] used preserved core plug samples to closely simulate the reservoir conditions while others [3, 4, 6-8, 16, 38, 48, 53, 82] employed a sand-pack. Moreover, differences in the experimental procedures may lead to different results in the same rock-fluid system.

4.1. Type of the oil phase

We first categorized the oil used into the two types as “Heavy oil” and “Light oil” depending on viscosity. Since viscosity exerts a direct influence on flow, we consider it more appropriate than density for oil classification. When the oil viscosity at ambient conditions is higher than 100 cP, we consider it a heavy oil. Most researchers [8, 15, 26, 32, 61, 83] believe that the flooding results for these two types are different; i.e., any judgment about the effect of temperature without considering the oil type is not reasonable.

The temperature’s impact on a heavy oil and light oil properties is significantly different. Even a small increase in temperature can reduce the viscosity of heavy oil sufficiently [2-7, 17] to affect the nature of flow. The temperature increase in thermal recovery operations causes the oil viscosity to change by several orders of magnitude [2-8, 15, 17, 26, 38]. In waterflooding of water-wet light oil systems, the mobility ratio is often favorable and the displacement is free of viscous fingering [15, 26, 29, 32, 61]. However, viscous fingering is difficult to avoid in waterflooding of a heavy oil systems [15, 26]. In light oil systems, the residual oil saturation can be reached typically with five pore volumes of water injection while it can take hundreds of pore volumes in heavy oil systems [6, 7, 15, 26]. On the other hand, it is much easier to establish the irreducible water saturation by oil flooding in heavy oil systems and the capillary end effects are small due to large pressure drop [6-8, 15, 26].

The literature review showed that majority of researchers used a light oil in their investigations rather than a heavy crude oil. Approximately 40% of studies used a light refined oil and 7% used a light crude oil. Heavy refined oil and heavy crude oil were used in 11% and 29% of studies, respectively and 13% of studies did not specify the type of oil phase. Only a handful of studies [2, 6, 7, 15, 17, 38, 84, 85] employed a heavy oil with viscosity higher than 1,000 cP at ambient temperature. The ambient temperature viscosity of oil used in the reviewed literature varied from 0.64 to 1,000,000 cP. The values of density and viscosity of the oil phase, as reported in the reviewed papers, are listed in Table 2.

Table 2. The oil phase properties employed in the literature.

Researcher	**Year**	**Light/Heavy oil**	**Viscosity (cP)**	**Density (g/mL)/(API)**
Wilson [86]	1956	Light refined oil	N/A	N/A
Odeh et al. [10]	1959	Light refined oil	0.42-71.30 (38 ºC)	0.72-0.88(38 ºC)
Edmondson [21]	1965	Heavy crude/light refined oil	7.5-100 (65.5 ºC)	0.862-0.975 (10 ºC)
Davidson [82]	1969	Light refined oil	65 (37.7 ºC)	0.863 (23 ºC)
Poston et al. [16]	1970	Light refined oil	80.3-600 (23.8 ºC)	22.4-26 (ºAPI)
Ehrlich [87]	1970	N/A	N/A	N/A
Sinnokrot et al. [23]	1971	Light refined oil	173 (21.1 ºC)	0.8645 (21.1 ºC)
Lefebvre du Prey [88]	1973	Light refined oil	0.56-60 (20 ºC)	N/A

Lo et al. [14]	1973	Light refined oil	2-130 (23 ºC)	N/A
Weinbrandt et al. [20]	1975	Light refined oil	65 (37.8 ºC)	0.863 (23 ºC)
Abasov et al. [43]	1976	Crude oil	N/A	N/A
Sufi et al. [51]	1982	Light refined oil	N/A	N/A
Amaefule and Handy [89]	1982	Light refined oil	0.6404-1.485 (25 ºC)	0.698-0.843 (25 ºC)
Torabzadeh et al. [24]	1984	Light refined oil	0.9782 (22 ºC)	0.7531 (22 ºC)
Maini & Batycky [15]	1985	Heavy crude oil	16,400 (22.8 ºC)	0.9815
Miller & Ramey [90]	1985	Light refined oil	30 (21 ºC)	N/A
Kumar et al. [40]	1985	Light refined oil	0.9782 (22 ºC)	0.7531 (22 ºC)
Bennion [44]	1985	Heavy refined/crude oil	N/A	N/A
Polikar et al. [7]	1986	Heavy crude oil	76.9±8.2 (125 ºC)	1.011-1.003 (15 ºC)
Nakomthap & Evans [41]	1986	N/A	30.91 (21.1 ºC)	N/A
Maini & Okazawa [8]	1987	Heavy crude oil	1,190 (21 ºC)	N/A
Closmann et al. [84]	1988	Heavy crude oil	900-10,000 (40 ºC)	1.5-10.9 (ºAPI)
Watson & Ertekin [19]	1988	Light refined oil	N/A	N/A
Maini & Kokal [63]	1989	Refined oil	500 (20 ºC)	N/A
Hawkins [91]	1989	Light refined oil	0.725-2.0	32 (ºAPI)
Polikar et al. [6]	1990	Heavy crude oil	N/A	N/A
Frizzell [46]	1990	Heavy crude oil	N/A	7-20 (ºAPI)
Kumar & Inouye [47]	1994	Heavy/light crude/refined oil	8.5-571.1 (160 ºC) 34.4-11450 (23 ºC)	N/A
Muqeem et al. [64]	1995	Heavy refined oil	450 (20 ºC)	0.875 (20 ºC)
Akin et al. [37]	1998	Heavy refined oil	220 (21.1 ºC)	0.878 (21.1 ºC)
Siddiqui et al. [92]	1999	Light refined oil	1.86-68.27 (37.8 ºC)	0.761-0.865 (37.8 ºC)
Esfahani et al. [12]	2004	N/A	N/A	N/A
Schembre et al. [50]	2005	Heavy crude/refined oil	640 (43 ºC)	N/A
Bennion et al. [38]	2006	Heavy crude oil	8,000-1,000,000	7.5-12 (ºAPI)
Wang et al. [11]	2006	Heavy/light crude oil	430-13,550	N/A
Sedaee Sola et al. [17]	2007	Heavy/medium crude oil	4-16,000 (37.8 ºC)	12-26 (ºAPI)
Hamouda et al. [13]	2008	N/A	N/A	N/A

Hamouda et al. [22]	2008	Light refined oil	N/A	N/A
Ashrafi et al. [3]	2012	Heavy crude oil	200-900 (50 ºC)	0.946-0.978 (15 ºC)
Akhlaghinia et al. [2]	2013	Heavy refined oil	1,500 (25 ºC)	10.71 (ºAPI)
Karaei et al. [93]	2013	Light refined oil	800 (25 ºC)	N/A
Ashrafi et al. [4]	2014	Heavy crude oil	200-900 (50 ºC)	0.946-0.978 (15 ºC)
Vega et al. [18]	2014	Light crude oil	7.20 (45 ºC)	0.87
Li et al. [94]	2014	Light crude oil	0.8-2.9 (23 ºC)	N/A
Nourmohhamad et al. [48]	2015	Light refined oil	25.1 (24 ºC)	N/A
Cao et al. [45]	2016	Light crude oil	18.2 (87 ºC)	31.5 (ºAPI)
Torabi et al. [42]	2016	Heavy/ light crude oil	24.3,400.2 (27 ºC)	0.926-0.965
Zeidani et al. [53]	2016	Heavy crude oil	N/A	N/A
Mosavat et al. [5]	2016	N/A	N/A	N/A
Zhang et al. [25]	2017	Light refined oil	50 (20 ºC)	N/A

4.2. Type of rock

Differences in the mineral content of rocks cause differences in rock surface properties, such as surface charge and type of chemical components adsorbed on the rock surface. In the presence of the oil and water phases in porous media, some components become adsorbed on the pore surfaces. This can make the surface hydrophilic or hydrophobic, depending on what is adsorbed. The contact angle, which is an indicator of wettability can be different for different types of rocks using the same fluids. The fluid distribution within the pore space is affected by wettability [29, 36, 56]. Therefore, the rock type has significant effect on phase distribution and thereby on the relative permeability of each phase [26, 27, 29, 35, 36, 56].

4.2.1. Sandstone vs. carbonate rock

Most sandstone reservoirs are water-wet while the carbonates are mostly oil-wet or weakly oil-wet. It is believed that the oil-wetness emerges after migration of oil into the reservoir by adsorption of polar components from the oil and this matter generally depends on the active adsorption sites and polar/nonpolar components present in water and oil phases [41, 95]. However, the adsorbed layer may become unstable and detach from the rock surface at high temperatures [41, 95], thereby causing the wettability to revert back to water-wet condition. Different types of porous media, including sandstone, diatomite, carbonate, chalk and even Teflon, have been employed to study the effect of temperature on relative permeability. Sand is the most often used material either in the form of unconsolidated sand or consolidated sandstone cores. Amongst carbonates, the dolomite and limestone are more prevalent than other types, like chalk. The polar components adsorb more readily on the carbonate rock surfaces; therefore, continuing experiments for a long time can alter the wettability of this type of rock. Besides wettability, other rock properties, like compressibility and pore geometry, can also differ significantly in different rock types.

The rocks used in relative permeability tests varied from thoroughly cleaned to fully preserved or restored. It is apparent that the initial wettability varied. For instance, several researchers cleaned the core by passing toluene through it followed by other solvents prior to each experiment [2, 16, 17, 23, 24, 89]. Furthermore, some core plugs were kept at a high temperature in a furnace for 24 hours to remove all the organic materials and diminish the clay activity. In contrast, the restored cores were used in several other investigations [12, 22, 47, 91, 92]. These cores had been flooded with the oil phase to achieve the irreducible water saturation and kept at the reservoir temperature for extended periods; hence, the polar components from oil could become adsorbed on the surface and restore the wettability. Sometimes, the researchers employed a preserved core or native one to eliminate any disturbances on the wettability as much as possible [6, 15, 38, 43, 44, 50, 84]. Approximately half of studies were carried out with clean porous media while preserved/restored/native cores were employed in 32% of them. Further details about the type of porous media as well as their other properties are listed in Table 3.

Table 3. The properties of porous media used in different investigations of the effect of temperature on relative permeability.

Researcher	**Year**	**Sand/carbonate Clean/Preserved/Restored/Native**	**Porosity (%)**	**Permeability (mD)**
Wilson [86]	1956	Clean core	23.20	16.8
Odeh et al. [10]	1959	Consolidated core	16.2-18.8	2.1-405.0
Edmondson [21]	1965	Clean consolidated Berea sandstone core	20.5-21.1	510-562
Davidson [82]	1969	Clean Tyler-grade Nevada sand and aquarium gravel (47–60 mesh size)	21.98	5,900
Poston et al. [16]	1970	Clean unconsolidated Houston (170-200 and 80-200 mesh size)	34 – 40	1,500
Ehrlich [87]	1970	N/A	N/A	N/A
Sinnokrot et al. [23]	1971	Clean Berea and Bandera sandstone core and clean carbonate core	19.7-21.5 26.6	152-610 865
Lefebvre du Prey [88]	1973	Clear Teflon, Stainless steel and Alumina	35-44.1	60-6,000
Lo et al. [14]	1973	Clean consolidated Berea sandstone and consolidated Teflon	21.6-24 40.1-45.4	560-620 1,180-2,400
Weinbrandt et al. [20]	1975	Clean consolidated Boise sandstone core	18.75-28.34	695-2,640
Abasov et al. [43]	1976	Native consolidated media	N/A	N/A
Sufi et al. [51]	1982	Clean unconsolidated Ottawa sand (170-200 mesh)	N/A	N/A
Amaefule and Handy [89]	1982	Clean Berea sandstone core	21.4-23.25	239.2-472.1
Torabzadeh et al. [24]	1984	Clear Berea sand stone core	24.3-24.57	643-969
Maini & Batycky [15]	1985	Native sandstone core plug	31-35.3	N/A
Miller & Ramey [90]	1985	1) Clean unconsolidated Ottawa sand (100-200 mesh size) and 2) consolidated Berea sandstone core	1) 38-38.3 2) 19	1) 6,750-7,160 2) 220

Kumar et al. [40]	1985	Clear Berea sandstone core	24.3-24.57	643-969
Bennion et al. [44]	1985	Native Sparky sandstone core	32	3,610
Polikar et al. [7]	1986	Clean Ottawa sand (200 mesh size)	32.1-35.8	1,347-2,067
Nakomthap & Evans [41]	1986	N/A	9.10	N/A
Maini & Okazawa [8]	1987	Clean Ottawa silica sand (140-170 mesh size)	N/A	3,000
Closmann et al. [84]	1988	Native Peace River sandstone core	28.8-34.7	39.9-653
Watson & Ertekin [19]	1988	Clean/restored Berea sandstone core	20.6-24.5	142.1-288.9
Maini & Kokal [63]	1989	Clean Ottawa sand (160-200 mesh size)	N/A	3,600
Hawkins [91]	1989	Restored granular carbonate core	20-26	9-26
Polikar et al. [6]	1990	Clean/native unconsolidated sand (170–230 mesh size)	34.0±1.0 27.0±4.0	958-2,070 504-1,656
Frizzell [46]	1990	Clean unconsolidated sand	N/A	N/A
Kumar & Inouye [47]	1994	Restored Berea sandstone and clean unconsolidated media	23	650-950
Muqeem et al. [64]	1995	Clean Sand (140-200 mesh size)	N/A	3,653
Akin et al. [37]	1998	Clean unconsolidated South Belridge sand (100-200 mesh size)	31	5,300
Siddiqui et al. [92]	1999	Restored Berea and Brown consolidated sandstone core	18.1-21.6	126-1,940
Esfahani et al. [12]	2004	Restored Carbonate core plug	8.20-24.90	1.5-130
Schembre et al. [50]	2005	Native Diatomite core plug	55-67	0.8-2.7
Bennion et al. [38]	2006	Native unconsolidated McMurray sand	N/A	4,567
Wang et al. [11]	2006	Clean unconsolidated Ottawa sand (60-100 mesh size)	35.6-36	6,680-7,690
Sedaee Sola et al. [17]	2007	Restored Carbonate core	11-21	0.2-3.0
Hamouda et al. [13]	2008	N/A	48.20	4.10
Hamouda et al. [22]	2008	Restored Chalk core	43.3-50.8	2.92-4.94
Ashrafi et al. [3]	2012	Clean unconsolidated glass beads (1000 and 300-425 micron)	28.8-34.26	90,000-100,000 40,000-45,000

Akhlaghinia et al. [2]	2013	Clean consolidated sandstone core	19.27	1,560
Karaei et al. [93]	2013	Clean unconsolidated sand (0.6-1.2 mm)	47-49.6	137,000-474,000
Ashrafi et al. [4]	2014	Clean unconsolidated Glass bead, sand and Restored Bentheimer Sand stone core	20.88-34.26	40,000-100,000 13,800-15,800 2,200-3,400
Vega et al. [18]	2014	Restored siliceous shale Diatomite core	63	0.7
Li et al. [94]	2014	Restored limestone core	17.15-17.49	0.314-0.358
Nourmohhamad et al. [48]	2015	Clean unconsolidated crushed carbonate (120-200 mesh size)	39.5	5,210
Cao et al. [45]	2016	Restored sandstone core plug	29.8–31.4	305.3-966,2
Torabi et al. [42]	2016	Clean Berea sandstone core plug	25	2,730-2,890
Zeidani et al. [53]	2016	Clean unconsolidated McMurray sand	N/A	N/A
Mosavat et al. [5]	2016	N/A	N/A	N/A
Zhang et al. [25]	2017	Sandstone core plug	16.15-17.48	7.10-179.94

4.3. Experimental procedures

There are many differences in the experimental procedures used in different studies. These procedures can be classified into two broad categories: steady-state method and displacement tests. The steady-state measurements maintain isothermal conditions and involve continued injection of a selected ratio of oil and water into the porous medium until the steady-state is reached in fluid saturation, pressure drop, and produced fractional flow of the two fluids [6, 7, 18, 24, 29, 36, 61-63]. This procedure yields the relative permeability of oil and water at a specific water saturation. The ratio of injected fluids is varied to obtain results at different saturations. The procedural differences in studies relying on the steady-state method are in the technique used for determining the saturation under steady-state conditions and in the strategy used for minimizing the impact of capillary end effects.

The displacement tests involve injection of one fluid to displace the other from the core, generally starting from very high saturation of the displaced fluid [31, 36]. The test is continued until the fractional flow of displaced fluid becomes practically zero [31, 36]. The relative permeability is calculated from the recorded pressure drop and production history [31]. To study the effect of temperature, most researchers have conducted such tests under isothermal conditions and repeated them at other temperatures [2-4, 6-8, 12, 14, 15, 45, 48, 53]. However, some studies have used incremental increase in temperature after reaching the residual oil temperature to evaluate the effect of temperature [17, 23, 37, 90]. It is an expeditious technique but limits the reliability of results to evaluation of the residual oil saturation and the endpoint water permeability, even though some authors have attempted to infer the whole relative permeability curve from such tests [17, 37]. The procedural differences in displacement tests are related to the methods used for establishing the starting saturation, the displacement velocity used in the tests, techniques used in monitoring the production and pressure drop, and whether or not the same core was used repeatedly.

4.4. Range of temperature used

The effect of temperature was examined over varying temperature ranges in reviewed studies; some involved a wide temperature range while others going up to only lukewarm conditions. More than 55% of researchers conducted their experiments at temperatures below 120 ºC and only 16% of studies were performed at temperatures higher than 180 ºC. It is expected that the changes that occur with increasing temperature would be amplified when the heating is continued to higher temperatures. In other word, some phenomenon related to the high-temperature condition may not be observable unless the temperature changes adequately. To clarify the distribution of temperature ranges in different studies, three different temperature ranges were defined as “low temperature range” (T<90 ºC), “moderate temperature range” (90 ºC<T<180 ºC) and “high temperature range” (T>180 ºC) in this research. According to this analysis, only 16% of studies were done in the high-temperature range, 37% in the moderate temperature range and approximately half of studies were carried out in the low temperature range.

5. EFFECT OF TEMPERATURE ON FLUID AND ROCK PROPERTIES

As the system temperature is increased, the properties of both fluids and the rock can change significantly. In this section, we examine the impact of temperature on properties that can have substantial effect on measured relative permeability.

5.1. Interfacial tension (IFT)

The IFT tends to decrease with increasing temperature [14-16] and this decrease can affect the relative permeability. To isolate the impact of temperature induced IFT reduction on relative permeability, it is necessary to find ways of changing only the IFT without changing the viscosity ratio, which can be even more temperature sensitive. Amaefule and Handy [89] accomplished this by evaluating the effect of IFT at constant temperature. Both steady-state and unsteady-state relative permeability measurement were carried out at 25 ºC. The drainage capillary pressure measurements were also conducted using the centrifuge method. They used an aqueous phase surfactant (Witco TRS 10-80 and Klearfac AA-470) to decrease the IFT to 0.01 mN/m from the value of 34.0 mN/m in the surfactant free system. A fired Berea sandstone core was used in these tests. For steady-state relative permeability measurements, the gravimetric approach was used to determine the saturations. They found that both the irreducible water saturation and the residual oil saturation decreased with the reduction of IFT. The residual oil saturation obtained by the centrifuge capillary pressure test was different from the value observed in relative permeability tests. This difference was attributed to differences in the fluid distribution. In the centrifuge test, the bond number affected the fluid distribution rather than the capillary number. In steady-state measurements, the relative permeability was considerably less affected by the IFT. The difference between steady- and unsteady-state relative permeability was attributed to the differences in distribution of fluid during the displacements.

Polikar et al. [7] reported that the interfacial tension decreased linearly with increasing temperature. The IFT values measured in the study by Poston et al. [16] also reported a reduction in IFT for three different oils at higher temperatures. Sinnokrot at al. [23] observed that the IFT decreased from 53 dynes/cm at ambient temperature to 32 at 163 ºC. A reduction of interfacial tension with an increase in temperature was also mentioned by Zhang et al. [25]. In Hamouda et al.[22] attributed lower residual saturation at higher temperature to higher capillary number due to the decrease in the IFT. Torabzadeh et al. [24] reported that the decrease in IFT with increasing temperature caused a reduction of irreducible water saturation. Edmondson [21] also accepted the role of IFT change on modification of the relative permeability curves with increasing temperature.

In contrast to the above mentioned studies, Lo et al. [14] reported that the reduction of IFT to less than 5 dyne/cm was not sufficient to change the oil and water relative permeability in their study using tetradecane and water system. They found no temperature dependency of relative permeability curves for tetradecane/water system at higher temperatures. The absence of significant effect of decreased IFT in Lo et al. [14] study appears to be due to the use of steady-state measurements in their work. As mentioned earlier, Amaefule & Handy [89] also found that decreased IFT affects the relative permeability measured by steady-state technique far less compared to the curves derived from displacement tests. In displacement tests, the impact of reduced IFT occurs mostly by reduction of oil trapping, which requires only modest increase in the capillary number.

5.2. Viscosity Ratio

The most prominent effect of increasing temperature in heavy oil systems is the dramatic reduction of oil/water viscosity ratio, which may have substantial effect on the oil/water relative permeability. Past researchers have investigated this issue two ways: (1) by using oils of different viscosity at constant temperature and (2) by using the same oil at different temperatures. Odeh et al. [10] conducted a theoretical analysis using a capillary tube bundle model of porous media by postulating that the oil phase cannot displace the water phase completely; therefore, a thin water film covers the rock surface. The thickness of this layer was found to be depended on the drag force which was related to the oil viscosity and velocity distribution profile [10]. According to their analysis, the effect of viscosity ratio decreases with increasing average pore radius and the oil relative permeability becomes independent of viscosity ratio for average pore radius higher than 4.5 microns.

Odeh et al. [10] also performed steady-state relative permeability measurements using four different oils. The electrical resistivity of cores was used for saturation measurements. In agreement with their theoretical model, the oil relative permeability (non-wetting phase) was a function of saturation and viscosity ratio of two phases, while the wetting phase relative permeability was only a function of its own saturation. Their experimental results showed that the effect of viscosity ratio was more pronounced when the absolute permeability of the medium was lower. They also reported a surprising finding that the effective permeability to a viscous oil could be considerably larger than the absolute permeability measured with water.

Lefebvre du Prey [88] postulated that the relative permeability to oil/water was related to the magnitude of viscous and capillary forces; therefore, changing these factors caused a variation in relative permeability. To prove this, they used three types of artificial porous media including Teflon, Stainless steel, and Alumina. The contact angle measurements showed that Teflon was strongly oil-wet, Alumina was strongly water-wet and stainless steel had intermediate wettability. Displacement tests were carried out at 24 ºC using different oils. The IFT varied between 0.25 – 350 dynes/cm and the viscosity of different oils varied from 0.9 to 60 cP. They concluded that the relative permeability to oil and water strongly depended on the balance between the capillary force and viscous force, whereby the oil and water relative permeability sharply increased as the value of $(\mu v/\sigma)^{-1}$ parameter decreases from 1,400,000 to 5,100. Their results showed that the residual saturations of both the wetting phase and the non-wetting phase increased with increasing value of $(\mu v/\sigma)^{-1}$ parameter.

Wang et al. [11] investigated the effect of viscosity ratio on the two-phase oil/water relative permeability using four stock tank oils and two crude oils diluted with kerosene at room temperature. It was found that the higher viscosity oils gave larger residual oil saturations. In addition, the relative permeability to oil and water as well as the endpoint relative permeability of water were lower in experiments conducted with higher viscosity oils [11]. The residual oil saturation increased linearly with log of viscosity and the irreducible water saturation decreased as the viscosity of oil increased. The lubricating effect of water film at the irreducible water saturation was suggested as a reason for the value of the endpoint oil relative permeability being higher than 1. The reduction of relative permeability to water and oil with increasing viscosity of oil was attributed to more severe viscous fingering.

Polikar et al. [6] stated that the shape of steady-state oil relative permeability in unconsolidated sand is affected by the viscosity ratio. The impact of the oil/water viscosity ratio on relative permeability measurements was also asserted by Ashrafi et al. [4], where the oil viscosity reduction caused the residual oil saturation to decrease and the irreducible water saturation to increase at higher temperatures. Esfahani et al. [12] also showed that the viscosity ratio can alter the characteristics of relative permeability curves at elevated temperatures. Torabi et al. [42] conducted two experiments with different oil viscosity while keeping the rest of parameters constant to investigate the effect of oil viscosity on two-phase relative permeability curves and, as can be seen in Figure 1, the oil viscosity had considerable impact on the relative permeability. The relative permeability also depended on the injection flow rate in this study [42]. In yet another study, the decrease in the residual oil saturation at higher temperature was attributed to the oil viscosity reduction of waxy oil, as reported by Cao et al. [45].

The involvement of viscosity ratio in determination of relative permeability was explained by Sufi et al. [51], who generated same results by increasing the flow rate or decreasing the viscosity at a given viscous force value. They showed that when any parameter affecting the viscous force changes, the relative permeability might also change. Kumar & Inouye [47] emphasized that not only the viscosity ratio, but also the wettability condition must be considered in examining the effect of temperature on relative permeability. Ashrafi et al. [3] suggested that the change in irreducible water saturation could be due to some experimental errors; although they believed that a large reduction of oil viscosity in comparison to water viscosity at higher temperatures could also be a reason for such variation.

The effect of temperature on oil and water relative permeability was claimed to be depended on the change in the viscosity ratio in a study conducted by Edmondson [21]. Lo et al.

[14] also observed that the residual oil saturation decreased with temperature due to the reduction of oil/water viscosity ratio at higher temperatures. The largest effect, in this study, was achieved for the highest oil viscosity [14]. Li et al. [94] showed that higher oil/water viscosity ratio or higher absolute permeability caused more oil to be trapped in porous media and resulted in higher residual oil saturation. This result was attributed to more pronounced water fingering at higher oil/water viscosity ratio and the difficulties in oil production after water breakthrough in higher permeability cases [94].

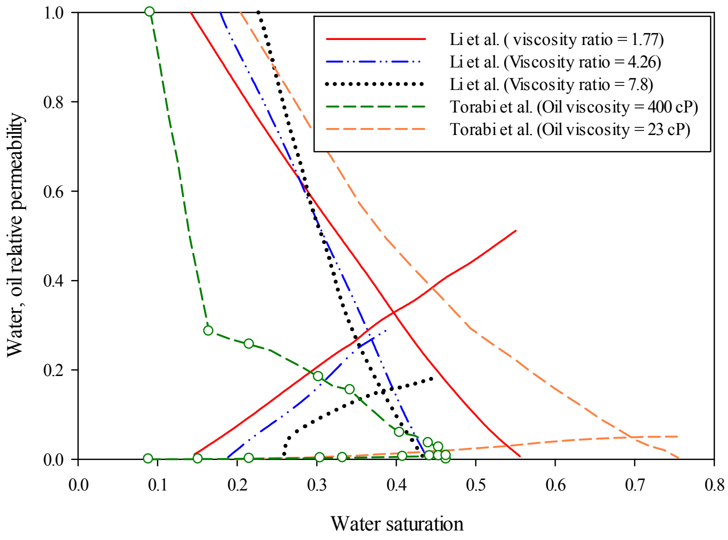

Figure 1. The effect of oil viscosity or viscosity ratio on two phase relative permeability [42, 94].

The opinion of a vast majority of researchers on the effect of viscosity ratio appears to be that it has a profound effect on oil-water relative permeability inferred from displacement tests. Yet there is no theoretically sound reason why this should be the case. If the fundamental assumption of the primacy of surface forces in controlling the fluid distribution within the pore space (which is the only justification for considering the relative permeability to be dependent only on saturation) is still valid, then the relative permeability should not change with oil viscosity. It suggests that there is a breakdown of the assumption of capillarity controlled fluid distribution in displacement tests involving high viscosity of oil. The fact that many of aforementioned studies have mentioned viscous fingering to be at least partly responsible for the observed effects of viscosity ratio confirms that the surface forces were not controlling the fluid distribution. It also means that the relative permeability curves inferred from displacements involving viscous fingering would be applicable only to displacements that have similar extent of fingering. It then becomes apparent that the steady-state method, which is generally not affected by viscous fingering, would be more reliable for measuring relative permeability in systems involving high oil/water viscosity ratio [26, 31, 61, 96].

The literature review also shows that the high oil viscosity reduces the irreducible water saturation and increases the residual oil saturation. These observations appear to be related to experimental conditions imposed in such tests. The reported residual oil saturation in most studies is the practical residual saturation that occurs when the fractional flow of oil becomes lower than a threshold value. When the oil viscosity is very high, the practical residual saturation may be much higher than the true residual saturation. On the other side, the irreducible water saturation is lower with high viscosity oil primarily due to much higher pressure gradients used during the injection of viscous oil, which not only provides more efficient displacement but also suppresses the capillary end effects at the production end.

5.3. Wettability and Contact Angle

The preference of the rock surface for oil or water as the wetting fluid stems from difference in the surface energies of rock-water and rock-oil interfaces. When the surface energy of rock-water interface is much smaller than that of rock-oil interface, the rock is strongly water-wet and vice-versa [35]. The equilibrium distribution of fluids in the pore space under capillarity-controlled conditions would be the configuration that minimizes the total surface free energy of rock-fluid and fluid-fluid interfaces. Therefore the wettability of rock surface plays an important role in controlling the fluid distribution and thereby determining the two-phase relative permeability [26, 29, 32, 35, 56].

The angle of contact of the oil-water interface at the line of contact with the solid surface is determined by the force balance involving solid-water, solid-oil and oil-water interfacial tensions [35, 97]. The interfacial tension of the solid and non-wetting phase interface is balanced by the sum of the interfacial tension of the solid and wetting phase interface plus the projection of the fluid-fluid interfacial tension on the solid surface [35, 98]. A small contact angle means a larger projection of the fluid-fluid interfacial tension is needed to counterbalance the solid and non-wetting phase interfacial tension with the two opposing forces [99]. Thus, the oil-water contact angle provides a measure of the difference between the surface energies of rock-oil and rock-water interfaces relative to the value of the oil-water interfacial tension and it can be used to assess the wettability of solid surfaces. However, it should be kept in mind that when the oil-water interfacial tension is very small, the difference between the rock-oil and rock-water interfacial energies would be very small, irrespective of the value of contact angle (assuming a stable contact angle exists). In this situation, the surface should be considered neutrally wet regardless of the value of contact angle and the contact angle is no longer a good indicator of surface wettability. Figure 2 shows the governing forces on a water drop immersed in oil.

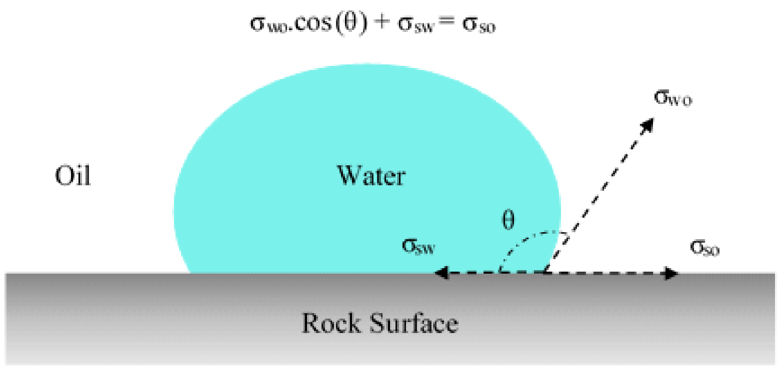

Figure 2. Schematic of a water drop showing the quantities in the Young equation [98].

Contact angle measurements have been used routinely to assess the effect of temperature on wettability [14, 16]. Other methods for characterizing the wettability of porous media include the Amott method [100] and the USBM method [101]. The wettability of a porous medium can also be assessed by examining the oil-water relative permeability curves and applying the Craig's rules [83]. In this method, the intersection point of oil and water relative permeability curves as well as the endpoint relative permeability to oil and water are indicators of the wettability [83].

Like the oil-water interfacial tension, the surface energies of rock-oil and rock-water interfaces can also change with temperature. Hence, the rock wettability can change with increasing temperature. Numerous investigators [4, 12-20] have endeavored to detect whether or not any wettability alteration occurred during their relative permeability measurements at elevated temperatures. Poston et al. [16] used contact angle measurements to evaluate the wettability alteration with temperature. Based on the results presented in Figure 3 for three different oil phases, the glass surface showed a tendency toward more water-wetness with an increase in temperature. Lo et al. [14] also measured contact angles at different temperatures and found no variation for Teflon, but a decreasing trend from 40° to 28° for the quartz surface.

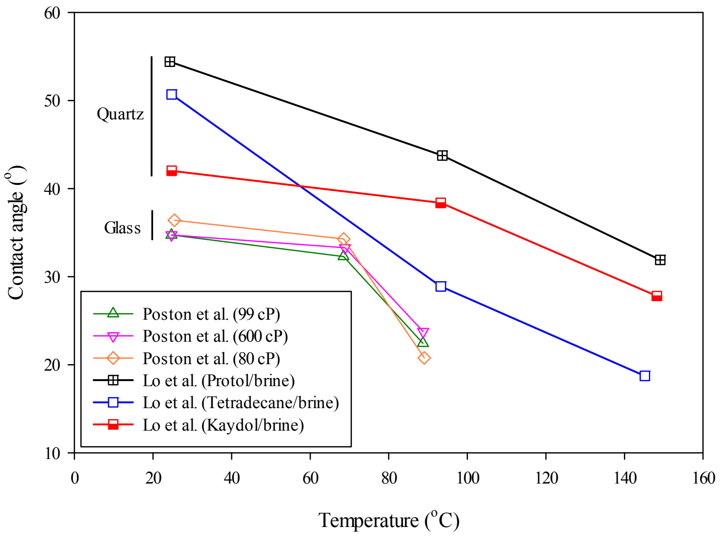

Figure 3. The variation of contact angle for some systems reported in the literature [14, 16].

Quantitative wettability evaluation was done by Esfahani et al. [12] using the Amott [100] and USBM [101] tests. The Amott-Harvey index for core samples at ambient temperature was in the range of -0.479 and -0.287, which indicated an intermediate to weak oil-wet system, while an oil-wet characteristic was observed at the higher temperature of 103 °C, with the Amott-Harvey index between -0.669 and -0.478. Table 4 summarizes the results of our literature survey regarding reported wettability alterations with increasing temperatures for various systems in different studies. Further information about the type of porous media and fluid properties in these systems are listed in Table 2 and Table 3.

Table 4. The variation of rock surface wettability at higher temperatures.

Researcher	**Year**	**Trend of wettability**	**Researcher**	**Year**	**Trend of wettability**
Poston et al. [16]	1970	More water wet	Sinnokrot et al. [23]	1971	More water wet (Sandstone)
Lo et al. [14]	1973	No change	Weinbrandt et al. [20]	1975	More water wet
Sufi et al. [51]	1982	No change	Torabzadeh et al. [24]	1984	More water wet

Maini & Batycky [15]	1985	More oil wet	Miller & Ramey [90]	1985	No change
Kumar et al. [40]	1985	More water wet	Nakomthap & Evans [41]	1986	More water wet (Based on the model)
Maini & Okazawa [8]	1987	More oil wet	Closmann et al. [84]	1988	More oil wet
Watson & Ertekin [19]	1988	More oil wet	Hawkins [91]	1989	No change
Akin et al. [37]	1998	No change	Esfahani et al. [12]	2004	More oil wet
Schembre et al. [50]	2005	More water wet	Bennion et al. [38]	2006	More water wet
Sedaee Sola et al. [17]	2007	More oil wet (Heavy oil/Limestone), More water wet (Light oil/Dolomite)	Hamouda et al. [22]	2008	More water wet at the temperature lower than 80 ºC and more oil wet at the temperature above 80 ºC
Karaei et al. [93]	2013	No change	Vega et al. [18]	2014	More water wet
Nourmohhamad et al. [48]	2015	No change	Zhang et al. [25]	2017	More water wet

6. THE EFFECT OF TEMPERATURE ON RELATIVE PERMEABILITY CURVES

As discussed above, several rock-fluid properties that can affect the relative permeability might change with increasing temperature. These include the surface energies of rock-fluid and fluid-fluid interfaces (which determine the wettability and affect the dominance of surface forces in controlling fluid distribution) and the viscosity of each fluid. The effect of temperature on relative permeability will therefore depend on whether or not changes in these properties in a specific system are substantial enough to affect the fluid distribution. Obviously, not all systems would be expected to display a change in relative permeability with an increase in temperature. Furthermore, a distinction should be made between cases where the change is sufficient to affect the fluid distribution but the dominance of surface forces is not compromised and cases in which the dominance of surface forces no longer exists. In the latter case, one has to question whether the concept of relative permeability is still appropriate to model the two-phase flow. Besides these issues, the variations in techniques used and the simplifying assumption made in interpreting the experimental results can also affect the outcomes.

Looking back critically into the previous investigations conducted over past six decades it becomes apparent that this issue is still not resolved and we need more research into the effect of temperature on reservoir systems. Although a large number of experimental studies have been carried out in different ranges of temperature and pressure using different porous media, the findings often contradict each other. Some researchers [6, 7, 37, 48, 51, 86, 90, 91] have concluded that the relative permeability to oil and water is independent of temperature even when the temperature increases by more than 200 ºC, while others [2, 20, 42] reported that even a small increase in temperature can change the oil/water relative permeability curves significantly. One can easily conclude that the effect of temperature would be system dependent but it is not clear in what type of reservoir systems one should expect the relative permeability to change more with temperature and in which direction.

To gain an insight into the reported effects of temperature on oil-water relative permeability, we have used six characteristics of relative permeability curves: (1) irreducible water saturation, (2) residual oil saturation, (3) endpoint relative permeability to water, (4) endpoint relative permeability to oil, (5) shape of water relative permeability curve, and (6) shape of oil relative permeability curve. The following subsections review the reported results on how temperature affects these parameters in different types of systems.

6.1. Irreducible water saturation

The irreducible water saturation (S_{wi}) is the lowest water saturation achieved by displacing water from the porous medium by injecting oil. At this saturation, water is no longer mobile, hence its saturation cannot be decreased further by displacement by oil. Actually, at least in strongly water-wet systems, the water remains continuous in the form of a wetting film on pore surfaces and its mobility does not become zero at a well-defined saturation [29, 56]. Therefore, S_{wi} measured in such displacement tests, in reality, is the saturation at which the water mobility becomes negligible compared to the oil mobility under the employed tests conditions. The measured S_{wi} can vary significantly with the capillary number used in the displacement (or the employed pressure gradient, which is an important factor in the capillary number) [24, 88, 89, 102]. Therefore, it is important to keep in mind that when similar flow rates are used, the pressure gradient becomes much smaller at higher temperatures due to much lower oil viscosity and some of the observed changes in S_{wi} with temperature might be related to changes in the pressure gradient. The irreducible water saturation is one of the factors used in determining the wettability state of the rock surface from relative permeability curves according to Craig's rules [83]. It should be noted that unless the test conditions were similar in terms of the capillary number (or at least the pressure gradient) used in the oil flood to establish S_{wi}, the change in S_{wi} is not necessarily related to a change in wettability.

The change of S_{wi} with temperature has been extensively investigated in a large number of experimental studies [3, 4, 12, 14-20, 23-25, 38, 40-42, 44-46, 51, 53, 94]. Although the results of different studies sometimes contain conflicting results regarding the effect of temperature, there is considerable consistency in the trend of S_{wi} with temperature. In the majority of reported studies [3, 4, 14-20, 23-25, 38, 40-42, 44-46, 51, 94], S_{wi} increases with temperature. However, several other experimental studies [6-8, 17, 23, 24, 40, 47, 48, 86, 90, 91] have found no variation with temperature and a decrease in the irreducible water saturation with increasing temperature has also been mentioned in some studies [12, 53].

Figure 4 compares some of the reported data from several different studies [3, 4, 14, 20, 25, 42, 51] on the effect of temperature on irreducible water saturation. S_{wi} was measured after 15 PV of oil injection at a rate of 0.1 mL/min by Zhang et al. [25]. To reduce the impact of capillary end effect, a filter paper was used at the production end of the core. In this research [25], the increase of temperature from 25 ^{o}C to 100 ^{o}C caused dramatic increase in S_{wi}. Since same flow rate was used at all temperatures but the viscosity of oil decreased by almost two orders of magnitude, the pressure gradient would be much lower in the high temperature tests and at least a part of this increase in irreducible water saturation is due to the reduced pressure gradient.

Torabi et al. [42] found that as the temperature increased by 18 °C, S_{wi} increased from 0.19 to 0.29. Their heavy oil viscosity dropped by almost one order of magnitude with this increase in temperature. Li et al. [94] also found that the value of S_{wi} in low permeability limestone increased from 0.2 to 0.3 with temperature increase of only 14 ^{o}C. Lo et al. [14] found that S_{wi} increased with temperature more dramatically when a viscous mineral oil was used compared to measurements with tetradecane. It is worth noting that the viscosity decrease was more pronounced for mineral oil than for tetradecane [14].

The displacement tests performed by Ashrafi et al. [4] demonstrated that S_{wi} increased as the temperature increased. This increase of the S_{wi} with temperature was attributed to water/oil viscosity ratio increase. They also found that a similar increase in S_{wi} could be observed when the oil viscosity is decreased at constant temperature, which confirms the role of the capillary number. Weinbrandt et al. [20] also reported a significant increase in S_{wi}, with increasing temperature. Sufi et al. [51] also observed an increase in the irreducible water saturation with temperature. They found that similar increase in S_{wi} could be obtained by decreasing the flow rate or decreasing the oil viscosity in the test without changing the temperature. By plotting S_{wi} against viscous force (product of flow rate and oil viscosity), they were able to show that the variation of S_{wi} resulting from changes in flow velocity, fluid change and temperature change fitted the same curve. They attributed the change in S_{wi} to change in the capillary end effect at the production end and more efficient displacement at higher viscous force [51].

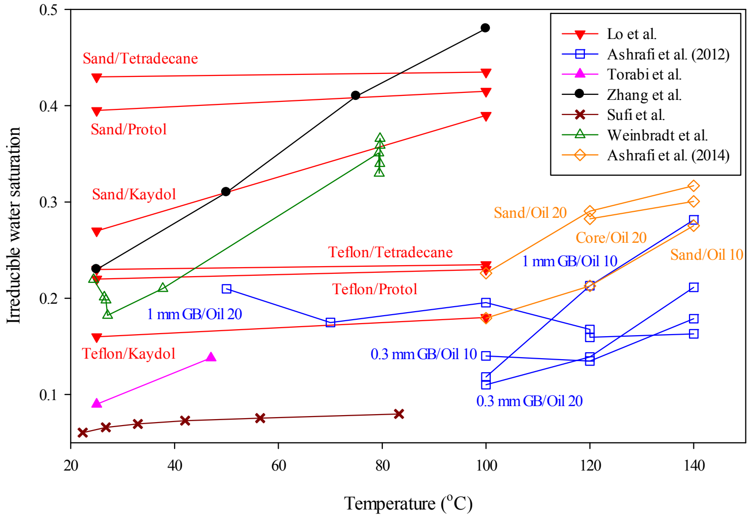

Figure 4. The increasing trend of irreducible water saturation with temperature for different systems [3, 4, 14, 20, 25, 42, 51].

Amaefule and Handy [89] established the irreducible water saturation by pushing 40 PV of oil into the core plug and found that S_{wi} increased with decreasing capillary number. Poston et al. [16] found that the increase in S_{wi} is less pronounced for clean unconsolidated sand compared to a reservoir sand. In addition, they found that the effect of temperature on irreducible water saturation was only partially reversible [16]. After exposure to high temperature, the repeat measurement in the same medium displayed slightly higher S_{wi}. They suggested that a part of the increase occurs due to increase in water wettability, which is not reversible and the rest is due to the change in water/oil viscosity ratio. Note that to calculate the irreducible water saturation, water volume was recorded until the water cut reached 1% or less. It was mentioned that the measured S_{wi} is not actually equal to the real irreducible water saturation but the same trend with temperature would be expected [16]. They suggested that there is significant change in the capillary pressure curve with increasing temperature due to changes in the interfacial tension and wettability, and this may be a contributing factor in the observed change in S_{wi}.

The CT scan analysis done by Vega et al. [18] showed that the average water saturation at zero water fractional flow increased from 0.16 to 0.62 as the temperatures increased from 45 °C to 230 °C. The tendency of the system toward more water-wetness by increasing the temperature was suggested to be responsible for it. Temperature dependency of two phase oil/water relative permeability and capillary pressure was investigated by Sinnokrot et al. [23] using restored-state approach applied to drainage and imbibition capillary pressure measurement at temperatures between room temperature and 163 °C. They employed the capillary pressure measurement to determine whether the hypothesis proposed by Poston et al. [16] for capillary pressure modification at higher temperature is true or not. The temperature was increased incrementally in order to prevent any disruption of the system. Moreover, the core plugs were fired to oxidize organic material within the core. The Brook and Corey [103] relative permeability model was used for drainage relative permeability curve estimation. The results of this study [23], shown in Figure 5, confirmed that the irreducible water saturation increases linearly with temperature for sandstone core, although at temperatures higher than 121.11 °C (250 °F), S_{wi} data deviated from the linear behavior. Moreover, the increasing behavior of S_{wi} intensified at 148.89 °C (300 °F), which suggests that the wettability of sand stone can be changed toward more water wetness, especially at temperatures higher than 148.89 °C (300 °F). Interestingly, S_{wi} did not change with temperature for the limestone core plug.

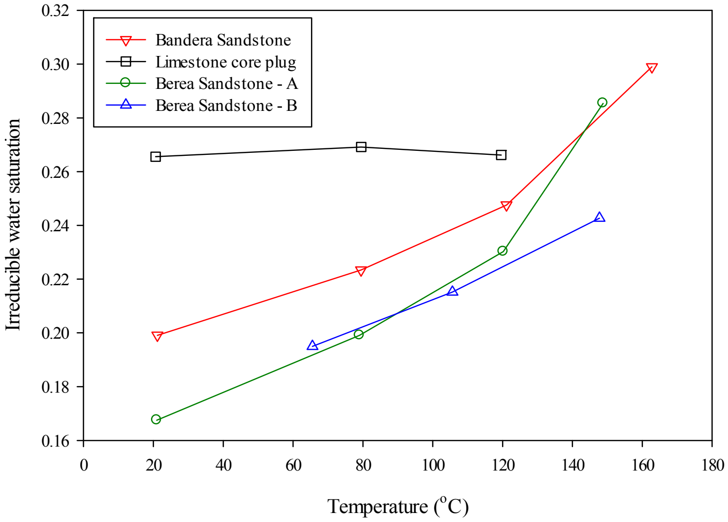

Figure 5. Different trend of S_{wi} with temperature obtained by Sinnokrot et al. [23].

Torabzadeh et al. [24] reported the results of irreducible water saturation at temperatures up to 175 ºC for the system containing 2% NaCl brine and n-dodecane in fired Berea sandstone core plugs. They found that 50 PV of oil injection was required to achieve the irreducible water saturation within high IFT system. An increase in water wetness in high IFT system was suggested as a possible reason for the observed increase of irreducible water saturation with temperature. The irreducible water saturation data from this study are shown in Figure 6. The low IFT system displayed only minor changes in the irreducible water saturation with temperature [24]. It is apparent that the capillary numbers were much higher in low IFT displacements and this lead to low irreducible water saturation at all temperatures.

An extensive analysis on 43 data sets of two phase relative permeability, measured over 15 years at high and low temperatures under hot water or steam injection, was performed by Bennion et al. [38]. The unsteady-state method was used in 41 out of 43 sets and steady-state approach was used for the other two. The temperature varied from 10 to 280 ºC. It is notable that all experiments were performed with low enough flow rates to minimize fines migration. Their results, shown in

Figure 7, indicate that the irreducible water saturation increases linearly with temperature, as represented by Equation 2. They also suggested that the initial water saturation at low temperature might be a function of absolute permeability.

$$S_{wi}=8.3\times10^{-4}T\left({}^{\circ}C\right)+0.135533 \tag{2}$$

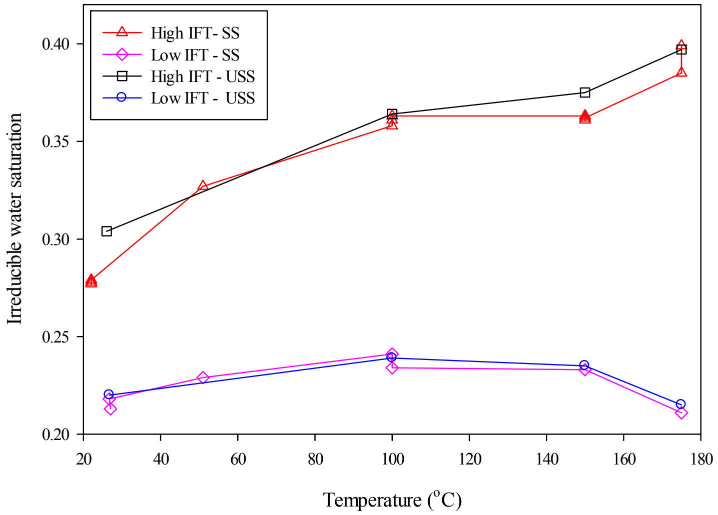

Figure 6. The irreducible water saturation versus temperature obtained by Torabzadeh et al. [24].

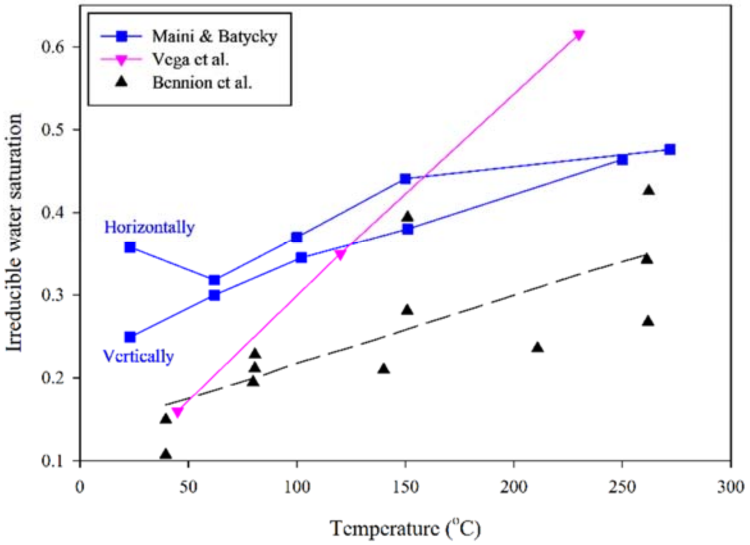

Figure 7. The irreducible water saturation behavior at different temperatures reported by different researchers [18, 38, 90].

The effect of temperature on two phase oil/water relative permeability was also examined by Sola et al. [17] using unsteady-state technique. The temperature influence was investigated over a wide range of 37.7 – 260 ºC under high pressure between 4.8 – 13.8 MPa. They employed two different procedures to evaluate the effect of temperature on relative permeability, where the temperature increased incrementally after reaching a specific criterion in some tests and remained constant during the whole tests in others. To determine the relative permeability curve, a black oil simulator with power law Corey model [104] was employed for history matching. The irreducible water saturation increased linearly with temperature in heavy crude oil systems but was independent of temperature for a lighter oil of 10 cP viscosity. Figure 8 presents their S_{wi} measurements in three different systems.

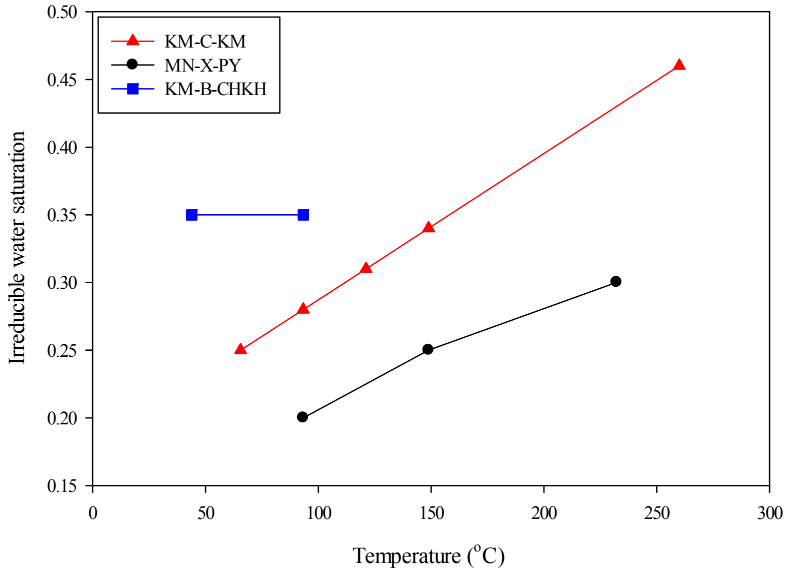

Figure 8. The effect of temperature on irreducible water saturation reported by Sola et al. [17].

The following empirical correlation for estimating the irreducible water saturation versus temperature was proposed by Frizzell [46] for unconsolidated sand.

$$S_{wi}\left(\%\right)=0.8472\times\left({}^{\circ}API\right)+0.0925\times\left({}^{\circ}F\right)-0.00062\times k_w+2.77 \quad (3)$$

Kumar et al. [40] proposed two separate empirical correlations for estimating the irreducible water saturation as function of temperature for normal IFT and low IFT systems, based on the data published by Torabzadeh et al. [24].

For high IFT:

$$S_{wi}=0.1828\times T^{0.1427} \quad (4)$$

For low IFT:

$$S_{wi}=0.1828\times T^{0.1427}+0.49835\sigma-0.17196 \quad (5)$$

Ashrafi et al. [3] studied the effect of temperature on heavy oil-water relative permeability in the temperature range of 50 to 140 ºC using two different blends of Athabasca bitumen and n-dodecane. The Sandra simulator using five different relative permeability models (Burdine [75], Corey [104], Sigmund & McCaffery [105], Chierici [106] and LET correlation [107]) was used for history matching of unsteady-state relative permeability measurements. The results generally showed that the irreducible water saturation increased with temperature [3]. It was pointed out that the effect of flow rate on displacement performance was examined by increasing the injection flow rate and making sure that the ultimate oil recovery did not change with flow rate [3].

An earlier study performed by Wilson [86] in 1956 showed that the irreducible water saturation was independent of temperature. The temperature was increased from 32 to 71 ºC while the pressure was varied from 0.2 to 34.46 MPa to capture the pressure effect. Their findings are not too surprising, since the change in water/oil viscosity ratio, with kerosene as the oil and such small increase in temperature, would not be that large.

Another major attempt to examine the issue was made by Polikar et al. [6]. The effect of temperature on relative permeability was examined using both the steady-state and unsteady-state techniques. Their results indicated that the irreducible water saturation was not significantly affected by temperature. Although there were some variations in their experiments, they believed them to be attributable to porous media heterogeneities. In another study, Polikar et al. [7] reported similar results for irreducible water saturation variation with temperature. The reduction of S_{wi} at higher temperatures observed by Polikar et al. [7] was attributed to solubilization of water phase into the large volume of the oil phase that passed through the porous medium. The values of irreducible water saturation in Polikar et al. [6, 7] studies are shown in Figure 9.

Hawkins [91] injected 10 PV of Blandol to obtain irreducible water saturation at ambient condition before heating the core to 100 ºC for 1000 hours to restore the wettability of the core and prepare it for an experiment at reservoir conditions. They reported that the irreducible water saturation was independent of temperature. This is not surprising since the water was displaced by injecting a viscous refined oil at ambient conditions in all tests.

Nourmohammad et al. [48] suggested that 15 PVs of oil injection is adequate to achieve the irreducible water saturation, which was reported to be 0.15 in all tests. It is notable that the temperature range in this study only varied from room temperature to 85 °C. The change in oil/water viscosity ratio was relatively small over the range of temperature used and apparently not enough to show any clear-cut effect of temperature on S_{wi}.

In the study of Maini & Okazawa [8], the oil phase was first injected into the sand pack at room temperature and then core was heated to the desired temperature, during which only oil was produced from the core. Therefore, the water saturation increased only due to the thermal expansion of immobile water, which was not a large change due to the low irreducible water saturation (5%) at room temperature. In Miller & Ramey [90], the irreducible water saturation at room temperature was determined by 2 PV of oil injection into 100% water saturated core. However, for higher temperature runs, the drainage displacement of water was conducted starting from residual oil saturation. They reported no change in irreducible water saturation by increasing temperature up to 150 °C in the unconsolidated sand pack and consolidated Berea sandstone core.

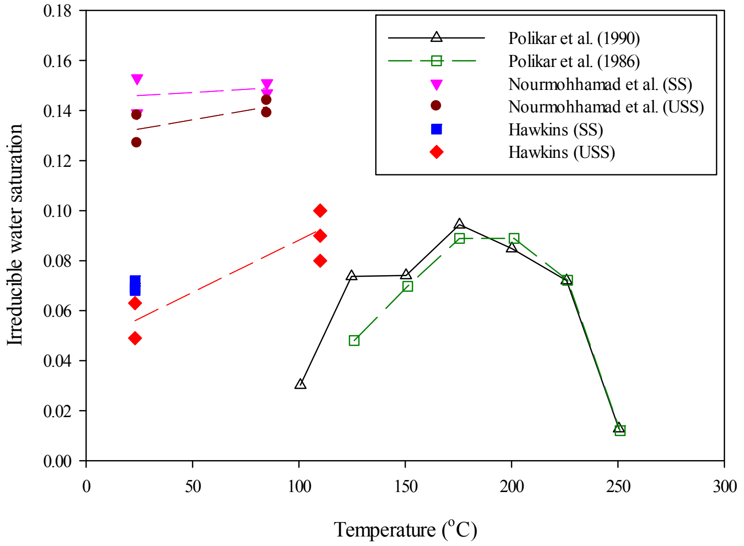

Figure 9. Comparison of the irreducible water saturation variation with increasing temperature [6, 7, 48, 91].

Reduction of irreducible water saturation with increasing temperature has been also reported in some studies. Two interesting papers about the reduction of irreducible water saturation with increasing temperature are the studies by Esfahani et al. [12] and Zeidani et al. [53] in 2004 and 2016; respectively. Esfahani et al. [12] applied the graphical JR [108] method to translate the transient production data acquired from unsteady state displacements. Five to ten pore volumes of oil were injected into the core to estimate the saturation endpoint. They reported a decrease in irreducible water saturation at reservoir condition and attributed it to increase in oil wetness at elevated temperature. Zeidani et al. [53] conducted SAGD experiments in a linear sand-pack at three different temperatures of 180 ºC, 200 ºC, and 220 ºC. The production and pressure response data were then converted to relative permeability curve using the history matching approach. The Corey [104] relative permeability model was used in CMG simulator to match the production data; however, the obtained simulation result did not fit the experimental result that well. The irreducible water saturation was used as an adjustable parameter in history matching of different tests [53]. The measured irreducible water saturation for these two studies is displayed in Figure 10.

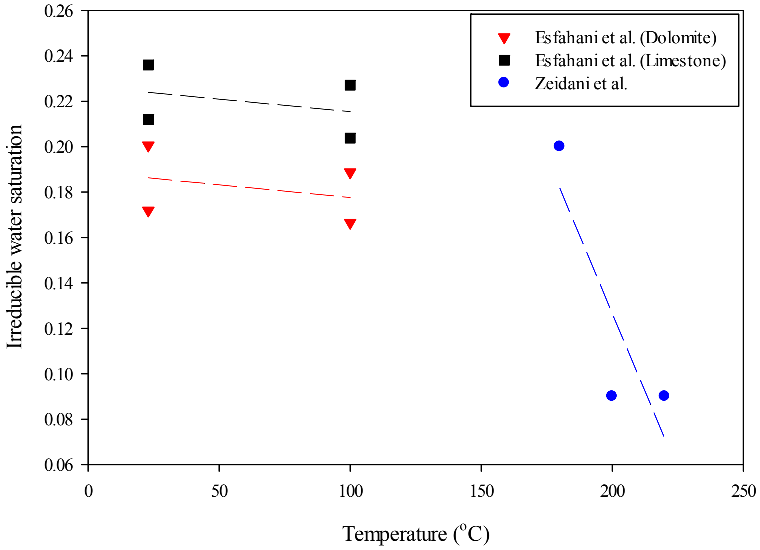

Figure 10. The decreasing trend of irreducible water saturation with temperature [12, 53].

The results obtained by Hamouda et al. [22] are also interesting. They conducted unsteady-state relative permeability tests. In order to alter the rock wettability, they used either n-decane with fatty acid additives [0.005 M SA (Steric acid) and 0.005M PODA (18-phenyloctadecanoic acid)] or n-decane without any additives. The wettability of cores were established by aging them at a temperature of 90 ºC before starting each experiment. The temperature range during the experimental measurements using distilled water with 0.005 M SA was from 23 to 130 ºC. The results, presented in Figure 11, show that the irreducible water saturation first increased slightly at the temperature of 50 ºC and then decreased more significantly up to the temperature of 130 ºC.

This matter has also been investigated by Gonari and Hamouda [109], Karoussi and Hamouda [110]; however, they paid more attention to other factors such as interaction potential in calcite/distilled water that becomes more repulsive at temperature over 70 °C. It explains how, in such systems, the wettability can change non-monotonically with increasing temperature.

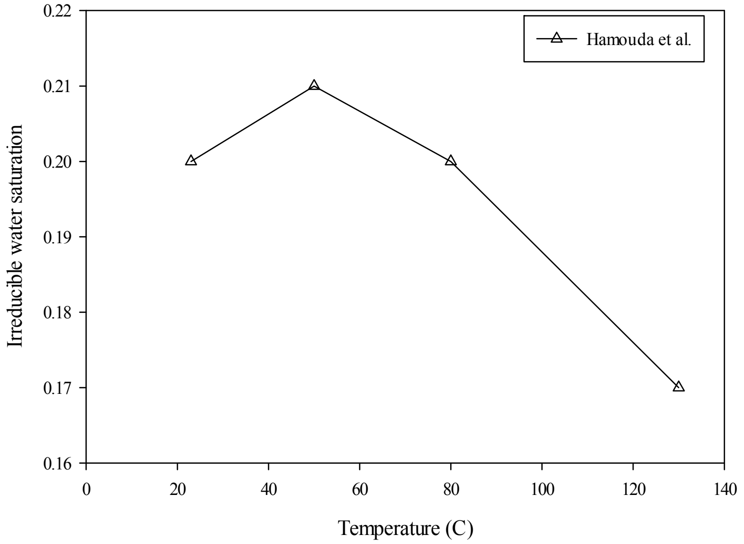

Figure 11. The behavior of irreducible water saturation determined by Hamouda et al. [22].

Watson & Ertekin [19] evaluated the effect of injected oil temperature on S_{wi} in cores of two different lengths. The initial temperature of the system was kept at room temperature in all tests. Their results suggest that the injected fluid temperature did not have any significant effect on irreducible water saturation on fired and unfired core plugs. Cao et al. [45] used a waxy crude oil of 45 °C pour point in reservoir core plugs. Their results, in Figure 12, show a steep increase in S_{wi} with increasing temperature. Results of Poston et al. [16], which were discussed earlier are also included in this figure for comparison and show a more modest increase with temperature.

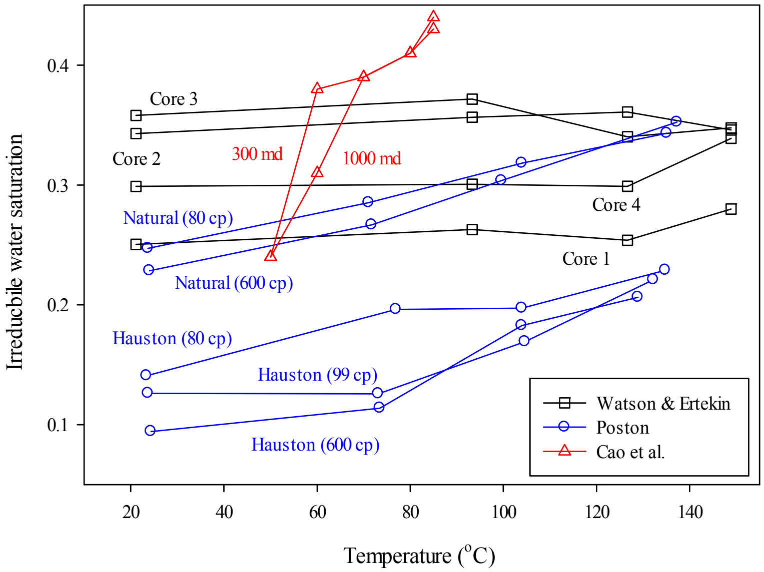

Figure 12. The variation of irreducible water saturation with temperature [16, 19, 45].

The preceding review of reported results tends confirms what was said in the beginning of this section that, in water-wet systems, the water relative permeability does not become zero at a well-defined saturation and the experimentally determined S_{wi} represents the water saturation at which the mobility of water becomes “negligible” compared to the mobility of oil under two-phase flow conditions. The actual definition of “negligible” is not same in all studies but in most studies it represents the condition at which the water mobility is of the order of 0.1% to 1% of the total mobility. Kumar & Inouye [47] stated that during the unsteady-state relative permeability measurements, the irreducible water saturation can be achieved when the fractional flow of oil at the outlet of the core reaches 99.9%. They pointed out that the true irreducible water saturation due to the presence of thin film flow cannot be obtained at all; therefore, the value of irreducible water saturation depends on total injected volume. The produced brine to oil volume ratio of 400 was accepted by Watson & Ertekin [19] as a critical value for determining the value of irreducible water saturation. Many researchers have used a minimum number of pore volumes of oil injected as a criterion for getting to the irreducible water saturation. For example, Akhlaghinia et al. [2] continued the oil injection to around 15 PV to achieve the irreducible water saturation. Cao et al. [45] obtained the irreducible water saturation by displacing water with 10 PV of oil. Weinbrandt et al. [20] also injected 10 PV of oil into the water saturated core to obtain the practical irreducible water saturation.

Another important issue in experimental measurements of S_{wi} is the necessity of minimizing capillary end effect at the production end. Water saturation remains high near the production end due to the need for capillary pressure to be equal on both sides of the production face of the rock under two phase flow. The capillary pressure is practically zero outside the rock, so it needs to be equally small at the face, inside the rock also. The zone of high water saturation extends some distance into the medium and it is imperative to make this zone very small compared to the length of the sample in measuring S_{wi}, so that the impact of such high water saturation at the end becomes negligible. This requires using high pressure gradient during oil injection to compress the capillary end effect zone. In our own work, we have found the pressure gradient of 50 psi/ft to be adequate and safe to use in most systems [26]. Higher pressure gradients sometimes lead to fines migration damage [38]. Unfortunately, many of the reviewed studies did not pay enough attention to this capillary end effect problem, especially in high temperature tests.

Theoretically, the irreducible water saturation depends on three factors: 1) the rock surface wettability, 2) pore geometry and 3) the capillary number used in the displacement of water by oil injection. In studies using clean unconsolidated sand and refined oil, it is unlikely that the wettability and pore geometry will change with increasing temperature. The capillary number used is an operational parameter that appears to be responsible for the increase in S_{wi} with temperature seen in many studies with such clean systems. In natural reservoir systems, the wettability can change with temperature due to change in the concentration of adsorbed species on pore surfaces [29, 38, 95]. In some systems, the pore geometry may also change due to rock-fluid interactions and thermal stress effects. In such systems, the value of S_{wi} can change significantly with temperature. However, many of the reported studies with such systems have paid insufficient attention to the impact of capillary number, which can change the apparent irreducible saturation even when there is no change in wettability.

6.2. Residual oil saturation

Among many studies of the effect of temperature on two-phase flow that have been reported during the past sixty years, a large majority of them [3, 4, 14, 16-18, 20, 21, 23-25, 38, 40, 42, 44-46, 50, 53, 82, 94] report that the residual oil saturation decreases as temperature is elevated. Nonetheless, several studies [8, 17, 19, 37, 47, 48, 51, 86, 90, 91] suggest that the residual oil saturation was independent of temperature. Very often, the measurement of this parameter is not exact due to experimental limitations in the measurements of relative permeability, such as limitations in the number of pore volumes that can be injected. The following review provides some insight into the current understanding about the effect of temperature on S_{or}.

An early study was conducted by Edmondson [21] in 1965 to assess the behavior of S_{or} and water/oil relative permeability ratio at high temperatures. Five different oil types including three mineral oils (No.5 white oil, No.10 white oil, and No.1 white oil) and two crude oils were employed to measure the two-phase relative permeability at temperatures ranging from 24 to 260 °C in two consolidated cores. Prior to the experiment, the cores were heated up to 400 °C for 24 hours to completely remove any organic material and desensitize the clays, and make the cores water wet. The definition of the residual oil saturation was based on the slope of the k_w/k_o value versus water saturation as the point where the value k_w/k_o approaches infinity [21]. Between 8 to

10 PV of hot water was injected in the displacements, which caused the fractional flow of water to oil to be 100:1 for the crude oil systems and 1000:1 for the white oil systems. The residual oil saturation was found to decrease with increasing temperature.

Davidson [82] conducted eleven unsteady-state relative permeability measurements. The temperature range was 22 to 282 °C. The residual oil saturation decreased with temperature irrespective of the absence or presence of the initial water saturation. Davidson [82] also investigated the effect of flow rate and initial water saturation and found that the flow rate did not affect S_{or}. His observations are shown in Figure 13. Two values are shown for each of the two systems (with and without initial water saturation), one obtained without any correction and the other corrected for solubility of water in the oil. Poston et al. [16] also investigated the temperature's impact on relative permeability to oil and water at temperatures up to 135 °C. The residual oil saturation was assumed to occur when the effluent had less than 1 volume % of the oil phase and it showed a decreasing trend with increasing temperature. This study suggested that a permanent wettability alteration had occurred at high temperature, whereas the previous researchers had considered the wettability alteration to be reversible [16]. Moreover, the higher viscosity oil showed greater temperature dependency of S_{or}. Their results of the residual oil saturation are shown in Figure 14.

Torabzadeh et al. [24] also reported a reduction of S_{or} at higher temperatures using eight unsteady-state and twenty two steady-state relative permeability measurements in two systems, one exhibiting high interfacial tension and the other with low IFT. As shown in Figure 14, the reduction of S_{or} was smaller in the high IFT system and more pronounced in the low IFT system. It was mentioned that due to the low oil viscosity, fluid flow was stable and a piston-like displacement occurred [24].

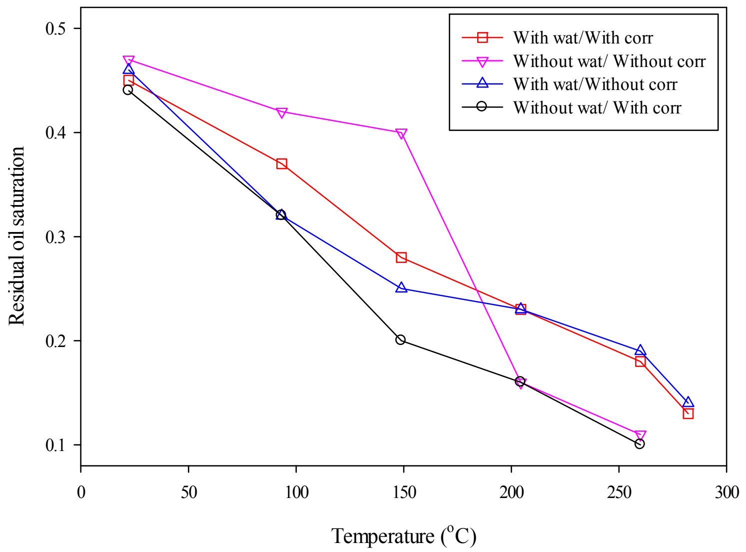

Figure 13. The residual oil saturation versus temperature obtained by Davidson [82].

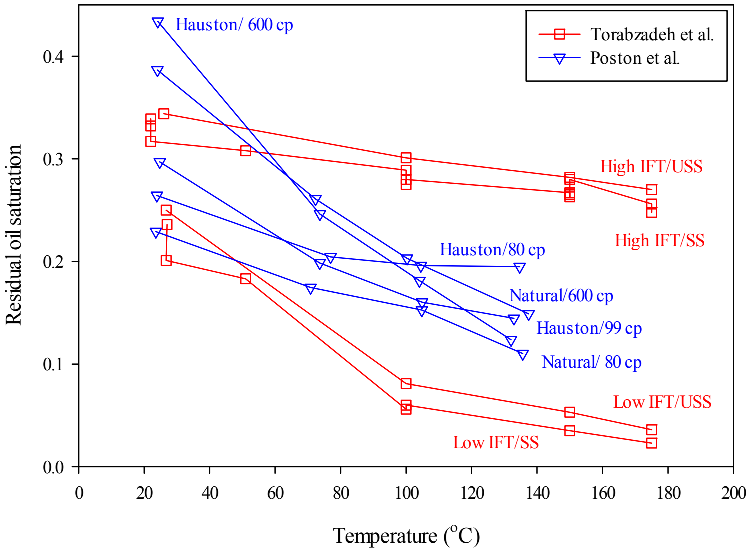

Figure 14. The reduction of residual oil saturation with temperature increasing [16, 24].

Lo et al. [14] used Teflon core as a strongly oil-wet medium and Berea sandstone core as a water-wet material to conduct steady-state relative permeability measurements. They installed a porous plate at the end of the core to minimize the impact of capillary end effects. An important issue in the steady-state measurement is accurate measurement of the saturation in the core, which they handled with the electrical resistivity measurements. Furthermore, they checked the material balance using the volume of collected effluent and compared it with the electrical resistivity measurement. They employed tetradecane and two white oils as the oil phase and 3% NaCl for the water phase. Prior to each test, the Berea core was heated up to 871 °C to eliminate the organic material and stabilize clays. They reported that S_{or} decreased with temperature and a larger decrease was seen for the higher oil viscosity. Their results are presented in Figure 15.

Many other researchers have evaluated the effect of temperature on residual oil saturation and found similar results. For example, Li et al. [94] reported that the residual oil saturation and the irreducible water saturation are a function of temperature when the temperature increase is high enough. In this study, the temperature range used was 86-100 °C at 30 MPa pore pressure. The cores were aged with simulated oil for three days at each experimental condition. The results were consistent with the previous researchers [3, 4, 14, 16-18, 20, 21, 23, 24, 38, 40, 42, 44-46, 50, 82] and the residual oil saturation decreased as temperature increased. Li et al. [94] attributed this result to the wettability alteration causing increased water-wetness of the rock at higher temperatures and they supported this idea on basis of the results from past studies [8, 111]. They suggested that higher oil/water viscosity ratio causes more oil to be trapped in porous media and results in higher residual oil saturation due to more pronounced water fingering [14]. Figure 16 includes the residual oil saturation results from this study.

Cao et al. [45] reported that the value of the residual oil saturation decreased from 0.569 to 0.236 when the temperatures was increased from 50 °C to 85 °C. They mentioned the possibility of higher flow resistivity due to the wax deposition at temperatures below 70 °C [45]. The results were similar in two sandstone cores of widely different permeability, as illustrated in Figure 16. Ashrafi et al. [4] also reported that S_{or} tended to decrease at higher temperatures. Sinnokrot et al. [23] observed the same trend in the Berea sandstone system, as shown in Figure 17.

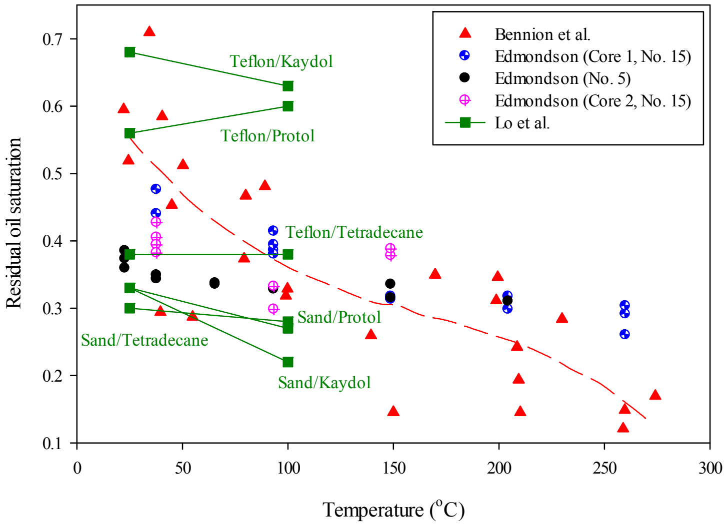

Figure 15. Comparison of the residual oil saturation trends at higher temperatures [14, 21, 38].

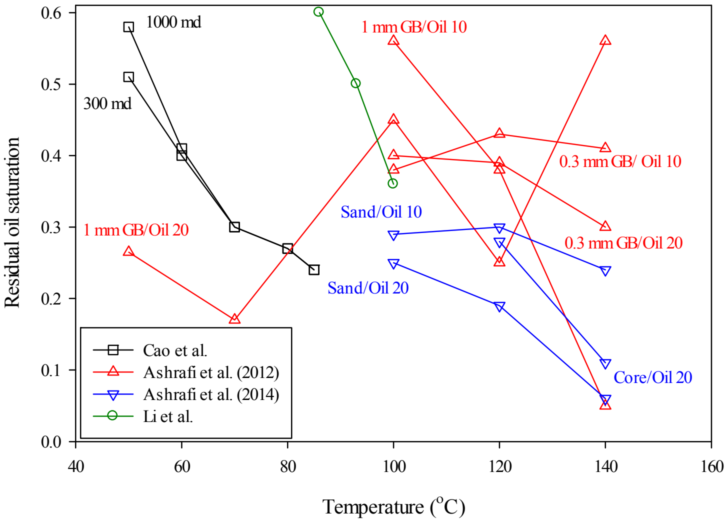

Figure 16. The variation of residual oil saturation for different porous media at elevated temperature [3, 4, 45, 94].

Vega et al. [18] used steady-state method for measuring oil/water relative permeability. For pre-cleaning the core plug, a few pore volume of decane injection and gas flushing followed by vacuum drying was used. CT-Scan confirmed a uniform water saturation distribution along the core at each temperature. A nonlinear reduction of the residual oil saturation with increasing temperature was observed, as can be seen in Figure 18. The capillary end effect was also examined in this study [18] by injecting water at f_w=1 with different flow rates and no variation in relative permeability characteristics were observed. In another study, Zhang et al. [25] determined the residual oil saturation by injecting 30 PV of water into sandstone core plugs and found that S_{or} decreased by increasing the temperature.

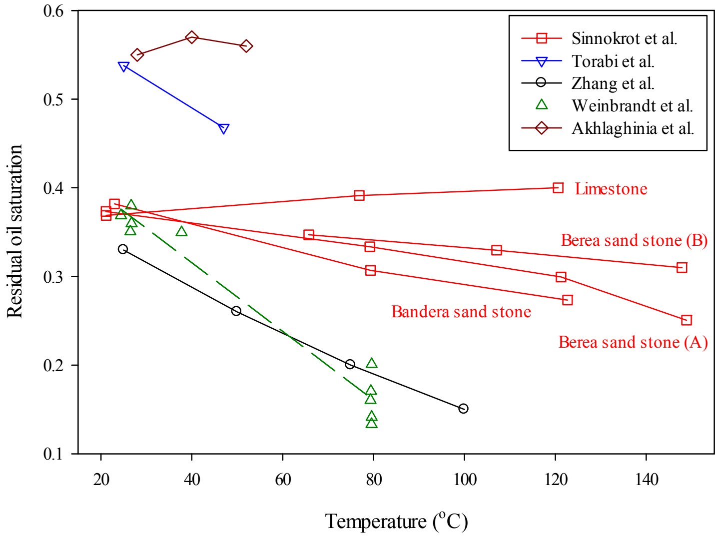

Figure 17. Different trends of residual oil saturation at higher temperatures suggested by some researchers [2, 20, 23, 25, 42].

It should be mentioned that in viscous oil systems, it is necessary to inject copious volume of water to achieve the true residual oil saturation and it is generally not practical to continue the waterflood to this extent [15, 26]. Different criteria have been used by researchers to terminate the waterflood. For example, Wang et al. [52] used the value of 99.9% water cut as the criterion to achieve the residual oil saturation in their experiments. 15 PV of the water injection was used by Akhlaghinia et al.[2]. Weinbrandt et al. [20] determined the residual oil saturations by injecting 10 PV of water. Unfortunately, such criteria do not ensure that the oil saturation is close to the true residual saturation when the oil viscosity is very high. For example, when the oil/water viscosity ratio is 10,000, as would be the case with many Canadian heavy oils at room temperature, the water cut of 99.9% occurs when the oil relative permeability is still 10 times higher than the water relative permeability! A relative permeability ratio based condition for assuming the oil saturation to be close to residual, such as $k_{ro}/k_{rw} < 0.01$, would be more reliable. However, for a 10,000 cP oil, this will require the water-cut to be below 1 ppm and may require many hundreds of pore volumes of water injection.

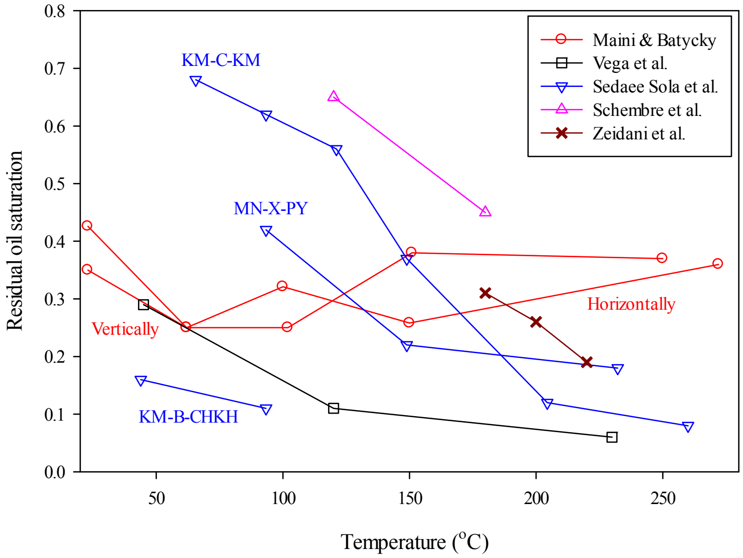

Figure 18. The behavior of residual oil saturation versus temperature [15, 17, 18, 50, 53].

Zeidani et al. [53] reported that the residual oil saturation decreased from 0.31 to 0.26 and then to 0.19 by increasing the temperature from 180 °C to 200 °C, and 220 °C; respectively. Schembre et al. [50] also observed a reduction of the residual oil saturation as temperature increased in diatomite core plugs. Frizzell's [46] developed a correlation, according to which the residual oil saturation will decrease by increasing the temperature and decreasing the specific gravity of oil. Their correlation shows that increasing the absolute permeability caused an increase in the residual oil saturation, which they attributed to the higher tendency of water fingering through the oil [46]. All the data employed in regression process were generated by injection of at least 2 PV of water or more until no oil was produced [46].

$$S_{or}(\%) = -0.6394 \times \left({}^{\circ}API\right) - 0.0619 \times \left({}^{\circ}F\right) + 0.00128 \times k_w + 51.15 \tag{6}$$

Another correlation was developed by Kumar et al. [40] by performing regression on the data obtained by Torabzadeh et al. [24]. Kumar et al. [40] believed that for high tension system (IFT>1.0 mN/m), the residual oil saturation was independent of IFT but decreased linearly with increasing temperature. For low IFT systems, the residual oil saturation varied with both the temperature and the IFT. These empirical correlations were stated as follows.

For high IFT:

$$S_{or} = 0.3267 - 3.9477 \times 10^{-4} T \tag{7}$$

For low IFT:

$$S_{or} = 0.3267 - 3.9477 \times 10^{-4} T - 2.825 \times 10^{-3} \sigma^{-2.0555} \tag{8}$$

For ultra-low IFT:

$$S_{or} = 1.68639 \times \left(\sigma / \left(T + 273.16\right)\right)^{0.42342} \tag{9}$$

They proposed another correlation based on the capillary number [46].

$$S_{or} = 0.2868 - 408.1\left[\tanh\left(N_c\right)\right] + 1.925 \times 10^5 \left[\tanh\left(N_c\right)\right]^2 - 2.663 \times 10^7 \left[\tanh\left(N_c\right)\right]^3 \tag{10}$$

Hawkins [91], evaluated the residual oil saturation at ambient conditions and at the reservoir temperature of 110 ^{o}C by injecting water until the water cut reached 99.9% and found that the residual oil saturation did not change significantly [91]. Bennion et al. [38] found that the residual oil saturation decreased with increasing temperature in hot water flooding. A cubic correlation was fitted to the residual oil saturation data versus temperature (in ^{o}C) during hot water flooding in McMurray unconsolidated sand containing 8-9 ^{o}API bitumen, which is valid for the temperature range between 10 and 280 °C.

$$S_{or} = -5\times10^{-8}T^3 + 2.612\times10^{-5}T^2 - 5.16927\times10^{-3}T + 0.6697519 \quad (11)$$

Sola et al. [17] determined the residual oil saturation during their relative permeability measurements when the oil fractional flow reached below 1%. There was no change in the residual oil saturation with a light oil (named CHKH oil) in the limestone core plug, while a reduction was observed with heavy oil in both the dolomite and limestone core plugs [17]. The reduction of the residual oil saturation displayed a linear trend in the experiments conducted under isothermal conditions but a non-linear behavior was detected when the temperature was elevated incrementally.

A reduction of the residual oil saturation from 0.54 to 0.47 was observed in the Torabi et al. [42] study. Ashrafi et al. [3] also concluded that the residual oil saturation can be reduced at higher temperatures. This reduction was attributed to the viscosity reduction and changes in viscous fingering during core flooding tests.

In 1982, Sufi et al. [51] conducted an experimental study to investigate the effect of temperature on oil/water relative permeability. The temperature was varied from 21 to 86 °C. They concluded that the residual oil saturation decreased with increasing temperature. Furthermore, they observed that by continuing the water injection after reaching 99% water cut, a slow reduction of the practical residual oil saturation was seen. They suggested that the practical residual oil measured at a preselected fractional flow of water (e.g. 0.99) might be temperature sensitive but the true residual saturation, which can be obtained only by injecting an infinite amount of water, would remain constant even at a higher temperature, as seen in Figure 19. They also found that the flow rate had an effect on relative permeability and residual oil saturation at the rates below 4.166 cc/min [51]. Above this flow rate, the residual oil and oil relative permeability were independent of the flow rate at room temperature [51].

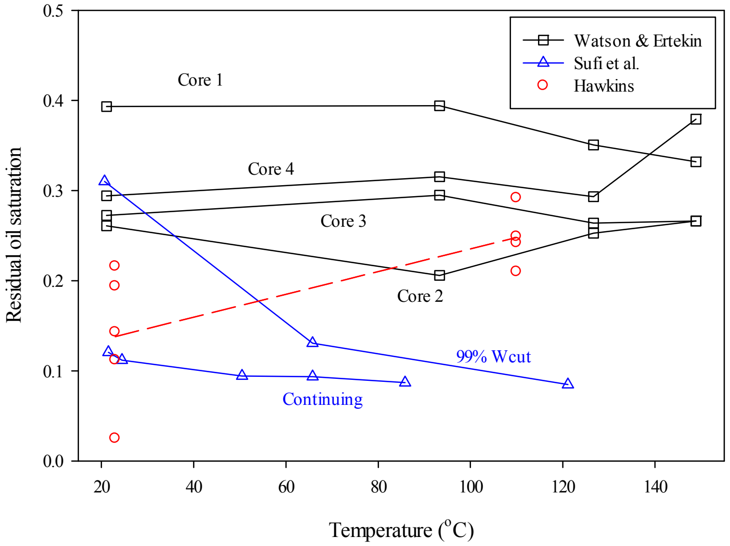

Figure 19. Comparison of the residual oil saturation variation with temperature increasing [19, 51, 91].

Miller and Ramey [90] used displacement tests to investigate the effect of temperature on relative permeability. They found the residual oil saturation to be independent of temperature. They mentioned that different results in this study compared to the previous studies were related to the use of low viscosity light oil.

Polikar et al. [7] evaluated the effect of temperature on endpoint of relative permeability to bitumen and water at elevated temperatures. The temperature was varied from 125 to 250 °C at a constant pore pressure of 7 MPa. They asserted that the saturation and relative permeability endpoint were apparently reached by pushing 4 to 5 PV of brine into the sand-packs. Their results showed that the temperature did not change the residual oil saturation significantly, as seen in Figure 20. A small variation of the residual oil saturation with temperature was attributed to the difference in sand-pack properties resulting from the packing procedure [7]. The effect of grain size and brine composition were also investigated in this study using different mesh sizes and adding Na_2SO_4 into the water phase, but no effect was detected. In another study, Polikar et al. [6]

found that the residual bitumen saturation in unsteady-state measurements was not reached after 4 to 5 PV injection and the recovery was enhanced by 18 % after injecting more than 45 PV.

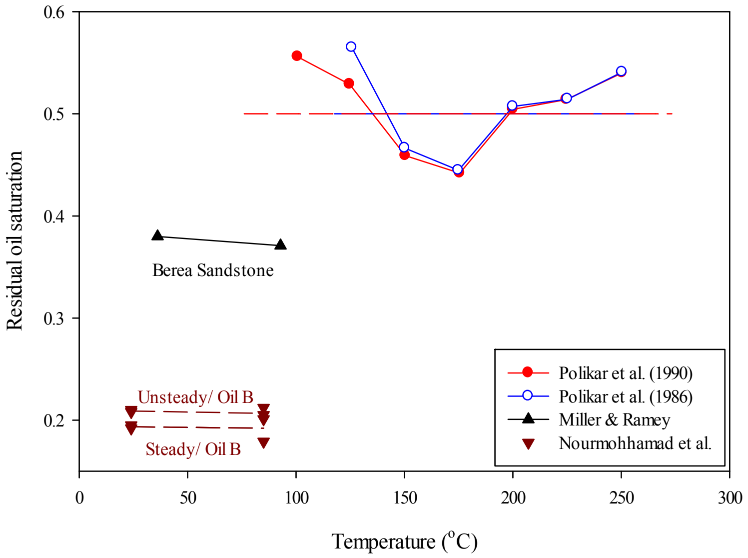

Figure 20. The residual oil saturation behavior at different temperatures reported by some researchers [6, 7, 48, 90].

The temperature was found to have no direct impact on the residual oil saturation within a temperature range of 24 to 85 °C in a study performed by Nourmohammad et al. [48]. Wilson [86] also observed the same result for the residual oil saturation. Watson & Ertekin [19] also demonstrated that the residual oil saturation was insensitive to the temperature in their experimental tests. The residual oil saturation was taken as a fixed value equal to 0.2 in the history matching process conducted by Maini & Okazawa [8].

Kumar & Inouye [47] injected more than 50 to 100 PV of water into the Berea sandstone core plug or unconsolidated porous media to obtain the residual oil saturation when the fractional flow of oil decreased below 0.1 %. They conducted three different experiments using different oils at different temperatures and obtained similar results. The largest difference between water saturation of two oils (White oil and silicon oil) occurred at the breakthrough time due to different wettability states [47]. The results of the residual oil saturation revealed that only the viscosity ratio affected this parameter and it was independent of temperature [47].

In a study done by Akin et al. [37] in 1998, the same conclusion (no effect) about the variation of the residual oil saturation with temperature was found. This study was conducted to check the temperature impact on heavy oil and water system at a temperature range between 23 and 65.6 °C. The experiments were performed at ambient temperature until no more oil was produced, and the temperature was then increased. It was found that the temperature had a small impact on the residual oil saturation in the applied temperature range [37]. This was attributed to the unstable fluid flow detected by the CT-Scan technique. The value of the residual oil saturation was around 0.12 at all temperatures. Esfahani et al. [12] conducted experimental measurements in limestone and dolomite core plugs. To clean these cores prior to each experiment, toluene was used as a solvent. After toluene flooding, all cores were placed in a furnace for 48 hours at a temperature of 400 °C. This study used only two different temperatures of 25 °C and 105 °C. The residual oil saturation in each core increased by about 2% at higher temperature. These values are shown in Figure 21. Maini & Batycky [15] used a different preserved core at each temperature and found that the minimum value of the residual oil saturation was reached between 60 and 160 °C. Their residual oil saturation values are shown in Figure 18 and the inconsistent trends suggest that the use of a different core in each test could have influenced the results [15]. Hamouda et al. [22] also stated that the residual oil saturation first decreased from 42% to 36% at 80 °C and then increased sharply up to 52% at 130 °C in a chalk core plug. Their results are shown in Figure 21.

The preceding review of residual oil saturation reveals that most studies have measured only the practical residual oil saturation after reaching some arbitrary threshold in terms of the fractional flow of water or pore volumes injected. This practical residual oil saturation decreases with increasing temperature when a viscous oil is used, primarily because a high water-cut can be reached with high viscosity oil even when the oil relative permeability is not close to zero. It is also apparent that in clean systems, such as Ottawa sand or fired sandstone with refined oil and water, the true residual saturation is independent of temperature. In real reservoir rocks with crude oil and brine, the true residual oil saturation can also change with temperature due to changes in wettability, interfacial tension and temperature induced changes in pore geometry. The direction and extent of this change can only be determined experimentally. In absence of experimental evidence to the contrary, the true residual oil saturation should be considered independent of temperature.

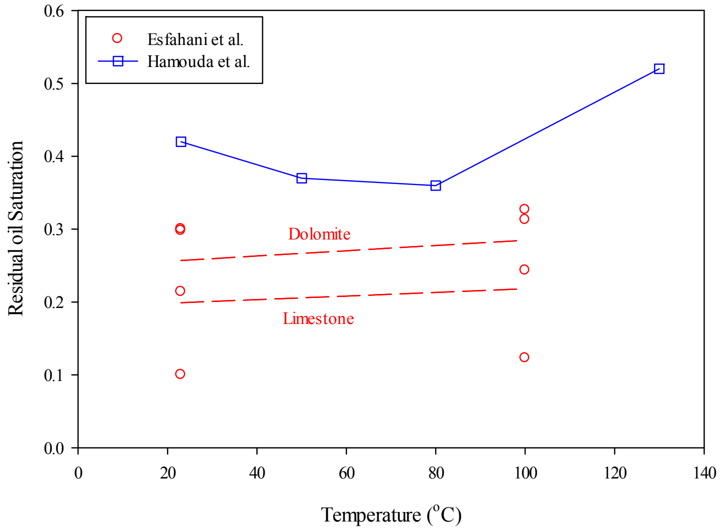

Figure 21. The value of residual oil saturation generated by Esfahani et al. [12] and Hamouda et al. [22].

For measurement of relative permeability in viscous oil systems, it would probably be better to first conduct measurements at an elevated temperature that lowers the oil/water viscosity ratio sufficiently to allow approaching the true residual oil saturation. The relative permeability determined from this experiment can then be tested for history matching displacements conducted at lower temperatures. If a good history match of the lower temperature displacement can be obtained, then the same relative permeability holds at the lower temperatures.

6.3. Endpoint of relative permeability to water

The endpoint relative permeability to water (k_{rw}^0) is the water relative permeability at residual oil saturation [29, 56], i.e. at the flood-out conditions when the oil is no longer produced in a waterflood . Like the effect of temperature on other relative permeability parameters, such as residual oil saturation or irreducible water saturation, there are conflicting results reported in the literature on it also. Craig [83] showed that the value of water relative permeability at the residual oil saturation is a good indicator of wettability. Accordingly, a change in wettability with increasing temperature would be expected to cause a shift in the end point water relative permeability; e.g. increased water-wetness would give lower k_{rw}^0. However, since the practical residual oil saturation tends to decrease with increasing temperature, the measured water endpoint shifts to higher water saturations at higher temperatures and this shift can increase the value of k_{rw}^0 (by extension of the curve to higher saturation) even when there is no change in wettability. Such increase in k_{rw}^0 can mask the decrease related to increased water-wetness.

The range of temperature's effect on k_{rw}^0 becomes apparent from the reported results presented in Figure 22 to Figure 26. Poston et al. [16] and Torabi et al. [42] reported an increase in k_{rw}^0 with increasing temperature. Sola et al. [17] also found an increase in k_{rw}^0 with temperature in a limestone core plug using a 26 °API oil but with a higher viscosity oil, they found no change in the endpoint in a dolomite core. Also, the temperature did not have any effect on the absolute water permeability due to the total absence or very small content of clay in dolomite or limestone rocks [17]. A small change of the water endpoint relative permeability was detected by Li et al. [94] where the endpoint increased by 0.04 at a higher temperature.

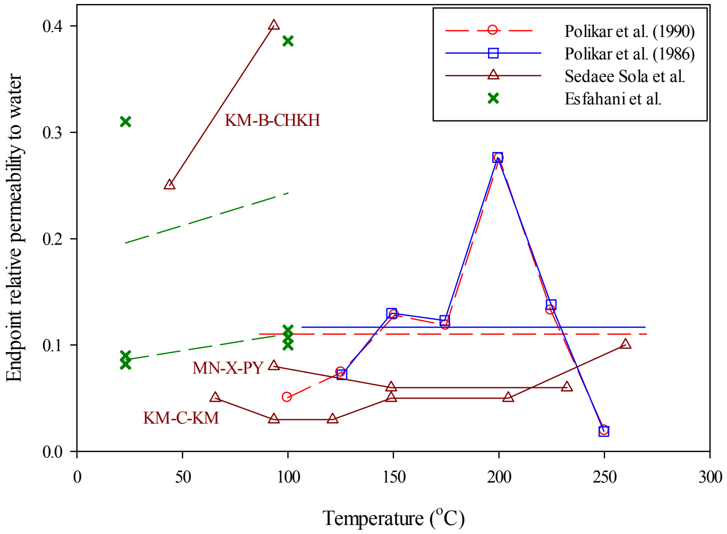

Figure 22. The water endpoint relative permeability at different temperatures reported by some researchers [6, 7, 12, 17].

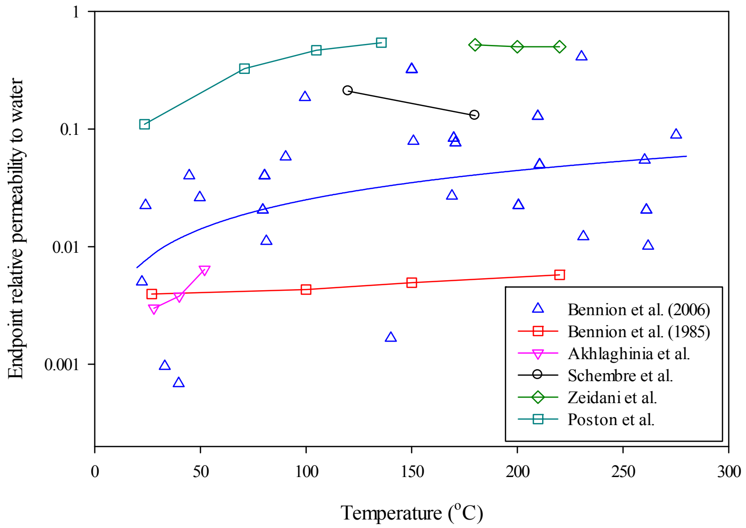

Figure 23. Different trends of water endpoint relative permeability at higher temperatures [2, 16, 38, 44, 50, 53].

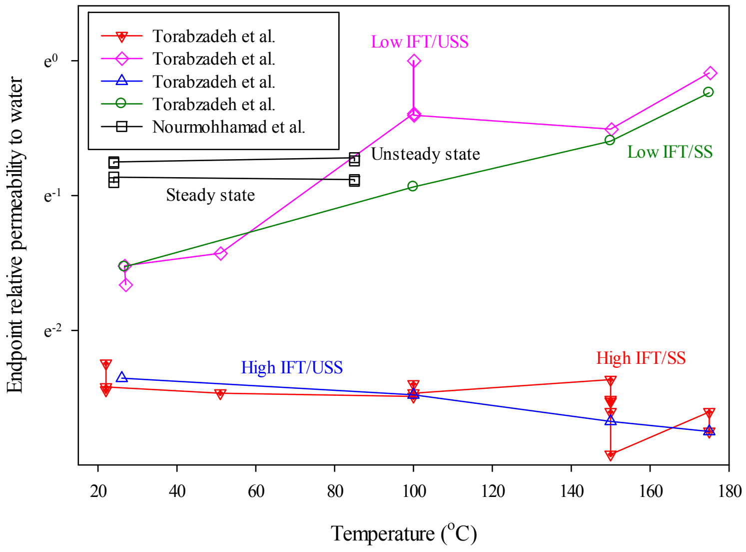

Figure 24. The variation of endpoint relative permeability to water for different systems [24, 48].

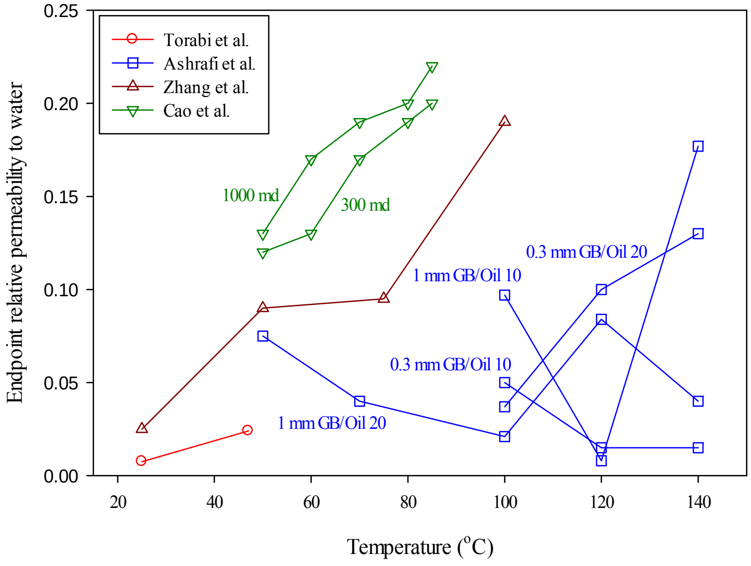

Figure 25. The changing in water endpoint relative permeability at higher temperatures [3, 25, 42, 45].

Bennion et al. [38, 44] showed an increase in k_{rw}^{0} when the temperature was raised. Torabzadeh et al. [24] also reported an increase by increasing temperature within a temperature range of 22–175 °C. An opposite results was obtained by Vega et al. [18] where k_{rw}^{0} decreased with temperature. They postulated that the absolute permeability was reduced by an order of magnitude and the porosity was also decreased at higher temperatures [18]. Mechanical stress, chemical, and transport-related mechanisms were some of the possible causes of this decrease in absolute permeability [18].

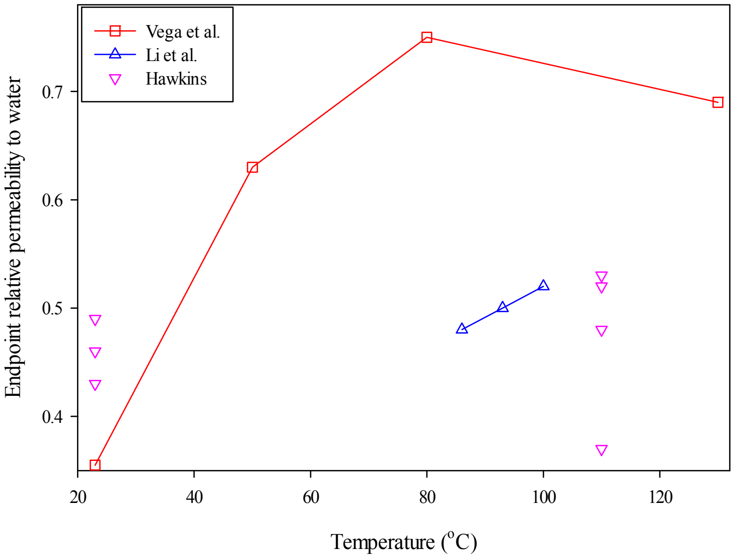

Figure 26. The comparison of the endpoint relative permeability to water with temperature increasing [18, 91, 94].

Hawkins [91] compared the results of unsteady- and steady-state tests at reservoir temperature (110 °C) with the steady-state results at the ambient temperature. They found that k_{rw}^{0} was significantly lower in the unsteady-state measurements (compared to steady-state tests) at ambient conditions [91]. Regarding the temperature impact, they suggested that the values of k_{rw}^{0} at reservoir and ambient temperatures were essentially the same; as a result, they concluded that the temperature did not affect the relative permeability to water at the residual oil saturation [91].

Torabi et al. [42] focused on eliminating the effect of physical properties of porous media on two-phase relative permeability measurements at higher temperatures by performing the experiments with the same core. After each test, the core was cleaned carefully and restored to its initial wettability condition. The effect of pressure, flow rate, oil viscosity, and temperature were examined. All measurements were conducted within a limited temperature range of 27 to 45 °C and at pressure of 1.72 MPa. In order to translate the production and pressure data of the unsteady-state measurements to relative permeability curve, the JBN method [112] was employed. By increasing either the pore pressure of the system from 1.72 MPa to 3.44 MPa or decreasing the temperature of the injected fluid, k_{rw}^0 decreased [42]. Furthermore, a reduction in k_{rw}^0 occurred when the flow rate was increased or the oil phase viscosity was increased [42]. Torabi et al. [42] suggested that in-situ oil emulsification during higher flow rate tests caused an improvement in k_{rw}^0. However, the increase in k_{rw}^0 with the small increase in temperature was not explained.

Zhang et al. [25] recently conducted tests on the effect of temperature on two-phase relative permeability. They used five different core plugs from a tight sandstone reservoir with strong heterogeneities, a simulated oil containing 0.3% asphaltene, and distilled water containing 2.1% KCl. The temperature remained constant in each experiment and a novel approach using a combination of the JBN method [112] and Corey correlation [104] was used to convert the production and pressure drop data into the oil and water relative permeability. They concluded that k_{rw}^0 increased with increasing temperature [25]. The wettability alteration occurred in this study was attributed to desorption of some polar components from the rock surface [25].

Polikar et al. [7] concluded that the water endpoint relative permeability was temperature independent at temperatures lower than 200 °C. However, Polikar et al. [6] also suggested that k_{rw}^0 at higher temperatures could have changed due to some experimental difficulties under high temperature condition. The system was water-wet based on the respective magnitude of relative permeability at endpoints [6]. The effect of sand-grain size using 100/120 and 20/45 mesh sizes was also investigated. Two different grain sizes with widely different permeability but same porosity were used and the measured endpoints showed similar results for both sand-grain sizes. Furthermore, different overburden pressures resulted in the same value of endpoint.

Watson and Ertekin [19] conducted experiments at temperatures between room temperature and 149 °C. Their experimental results showed that k_{rw}^{0} decreased with increasing temperature. They mentioned that the reduction of k_{rw}^{0} might be due to the apparent wettability alteration by increasing temperature [19]. However, based on the observed reduction of both water and oil relative permeabilities, they could not conclude that the wettability was changed. Therefore, they suggested that any judgment about wettability alteration based on the value of the irreducible water saturation or endpoint of oil and water relative permeability hypothesized by Craig's rule [83] is not reliable and contact angle measurements are needed to confirm the wettability change. Their values of endpoint relative permeability to water are shown in Figure 27 at different temperatures.

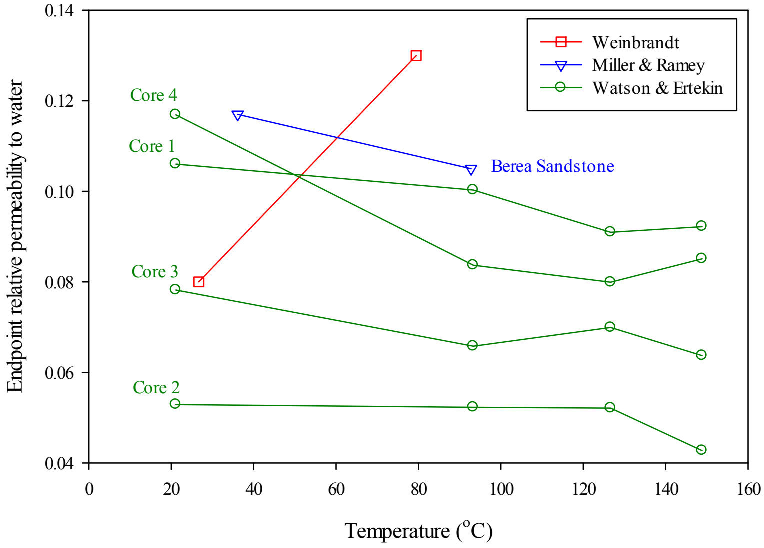

Figure 27. The different trends of endpoint relative permeability to water versus temperature [19, 20, 90].

Maini & Batycky [15] claimed that k_{rw}^{0} was generally not modified with increasing temperature. Maini & Okazawa [8] reported that k_{rw}^{0} increased from 0.085 to 1.50 μm^2 during temperature increase of approximately 180 °C. In contrast Miller & Ramey [90] showed that k_{rw}^{0} remained constant at high temperatures. They also mentioned that the temperature did not have an effect on water absolute permeability in the unconsolidated sand, while this value was reduced permanently from 310 md to 190 md as temperature increased up to 93 °C in a consolidated Berea sandstone core. No modification was observed by Nourmohammad et al. [48], Wilson [86], and Sufi et al. [51]. However, a significant variation of k_{rw}^{0}, showing both increasing and decreasing trends, with temperature was reported by Ashrafi et al.[3] in clean glass-bead packs. A significant reduction of k_{rw}^{0} at higher temperatures was recorded by Schembre et al. [50] in diatomite cores.

An empirical correlation for water relative permeability at the residual oil saturation was developed by Frizzell [46], which is expressed as Eq. (12). An increase in the endpoint relative permeability is expected at higher temperatures from this correlation [46].

$$\begin{aligned} k_{rw}\left(S_{or}\right) = \exp\Big[& -2.905 + 0.08927\times\left({}^{\circ}API\right) + 0.0012\times\left({}^{\circ}F\right) + 0.9565\times\ln\left(k_{w}\right) \\ & -0.0255\times\left(S_{wi}\right)\Big] \end{aligned} \tag{12}$$

Hamouda et al. [22] found that the water endpoint relative permeability increased in going up to 80 °C (from room temperature) and then it decreased slightly at 130 °C. The change was attributed to wettability alteration and decrease of absolute permeability with increasing temperature [22].

Although it is obvious from the foregoing that the effect of temperature on endpoint water relative permeability is different in different rock-fluid systems, some generalized observations can be made for thermal recovery of heavy oils. The review suggests that the variation of k_{rw}^0 with temperature is not related to the rock cementation. However, carbonate rocks display greater tendency of changes in k_{rw}^0 with temperature. The heavy oil viscosity changes dramatically with increasing temperature, which results in a significant reduction of the practical residual oil saturation. Recall that the residual oil saturation is typically measured by continuing the displacement until the oil-cut becomes lower than a threshold value (e.g. 0.01 or 0.001). The residual oil saturation measured at such threshold oil-cut will decrease with increasing temperature even when there is no change in relative permeability and this will move the endpoint to higher water saturation, resulting in higher k_{rw}^0. Therefore, in absence of any change in wettability and interfacial tension, the endpoint relative permeability to water measured at a set fractional flow threshold should be expected to increase with temperature. In systems that involve a significant change in wettability, its impact will be superimposed on the effect of reduced residual oil saturation due to increased mobility of the oil. Generally, the wettability appears to shift towards increased water-wetness, which would tend to reduce the endpoint relative permeability to water. In many cases, the impact of increased water-wetness counterbalances the impact of decreased residual saturation and results in no significant change in end-point water relative permeability.

6.4. Endpoint of relative permeability to oil

The endpoint of relative permeability to oil (k_{ro}^0) is the value of oil relative permeability at the highest attainable oil saturation when oil displaces water [29, 56]. Often, the connate water saturation in typical reservoirs is equal to the irreducible water saturation and the initial relative permeability to oil is this endpoint value. Previous studies [29, 56] have reached a consensus that the endpoint of relative permeability to oil phase depends primarily on the wettability state of the rock surface. Based on Craig's rule [83], k_{ro}^{0} is an indicator of the wettability state of the rock surface and higher values correspond to more water-wet systems. In a strongly water-wet system, the irreducible water saturation would exist as a wetting film on pore surfaces of oil filled pores, or as pendular rings at grain contacts and perhaps as pore filling fluid in very small pores [57-60]. This water saturation causes little or no interference to flow of oil and therefore almost full conductivity of the porous medium becomes available to the oil. It means that k_{ro}^{0} would be expected to be close to 100% in strongly water-wet systems [56-58]. If the increase in temperature makes the system more water-wet, k_{ro}^{0} should be expected to increase, but if its value was already close to 100%, there would be little room left for such increase. Moreover, if the irreducible water saturation becomes larger at higher temperatures, there could be greater interference in the flow of oil due to the presence of water and a reduction in k_{ro}^{0}.

By reviewing previous studies done during the past sixty-five years, no firm conclusion about the effect of temperature on k_{ro}^{0} could be extracted. Experimental studies have reported a full range of possibilities. Wilson [86] found that k_{ro}^{0} remained constant. Poston et al. [16] also found k_{ro}^{0} to be independent of temperature. The end point to the oil phase at different temperatures was reported equal to the unity in all cases but no further explanations as to reasons for this were offered [16]. In another study done by Sufi et al. [51], the results clearly showed that k_{ro}^{0} was not a function of temperature and it was equal to unity at different temperatures. Maini & Okazawa [8] had similar opinion about the oil relative permeability at irreducible water saturation. They demonstrated that, in clean unconsolidated sand, the effective permeability to oil at irreducible water saturation remained constant at different temperatures.

Miller and Ramey [90] investigated the effect of temperature on relative permeability for consolidated Berea sand stone. The oil and water flood behaved almost as piston-like displacements, therefore the relative permeability curve could not be determined and only the endpoints of relative permeability values were obtained [90]. They concluded that within the accuracy of measurements, the endpoint was independent of temperature.

Several other scholars have also reported no dependency of k_{ro}^{0} with temperature. Schembre et al. [50] performed experimental tests with unsteady-state approach to measure the transient relative permeability of two phases with time. All spontaneous countercurrent water imbibition tests were conducted at a temperature range between 120 and 180 °C and Simulated Annealing method was applied to estimate the instantaneous relative permeability and capillary pressure curve under unsteady-state conditions [50]. Their conclusion was that k_{ro}^{0} does not change significantly with temperature. Sola et al. [17] showed different results about the oil relative permeability at irreducible water saturation. In their work, prior to each experiment, the core was completely washed with toluene for three days and dried for at least 24 hours at the temperature of 148.8 °C (300 °F) to remove all organic material from the rock surface. The results generated during experiments with heavy oils named “PY” and “KM” on limestone and dolomite confirmed that temperature did not change k_{ro}^{0}, while the increase in temperature in the system containing a medium oil named “CHKM” in limestone core shifted the relative permeability endpoint from 1.0 at 37.8 °C to 0.2 at 93.3 °C [17]. As a result, they suggested that two different behaviors could be obtained in the limestone core sample, depending on the oil used. A decrease of endpoint relative permeability to oil with temperature was also reported by Vega et al. [18], as shown in Figure 28, as well as by Esfahani et al. [12] on carbonate core plugs. Results of Watson and Ertekin [19], shown in Figure 29, also reveal a similar trend.

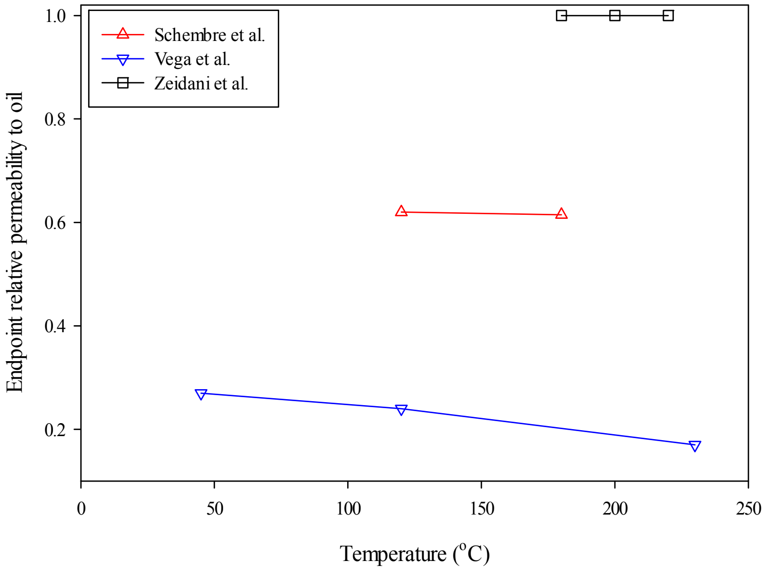

Figure 28. Comparison of k_{ro}^{0} versus temperature [18, 50, 53].

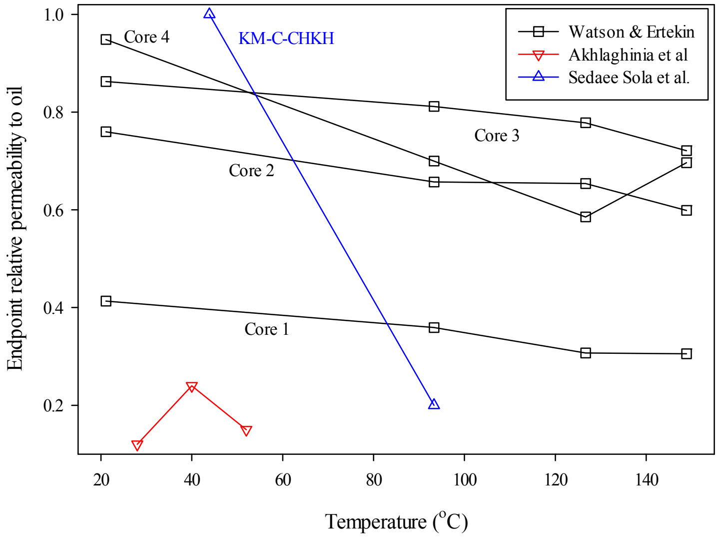

Figure 29. The behavior of endpoint relative permeability to oil versus temperature [2, 17, 19].

Polikar et al. [6] showed that temperature did not affect k_{ro}^{0} significantly, although it was observed that the absolute permeability decreased with increasing temperature in some of the tests.

They concluded that the temperature had a small effect on absolute permeability of the clean, unconsolidated Ottawa sand packs [7]. The results of these studies are illustrated in Figure 30. Polikar et al.[6] suggested that the clay movement was a possible reason for absolute permeability change. Torabi et al. [42] also reported k_{ro}^{0} to remain unchanged at higher temperatures.

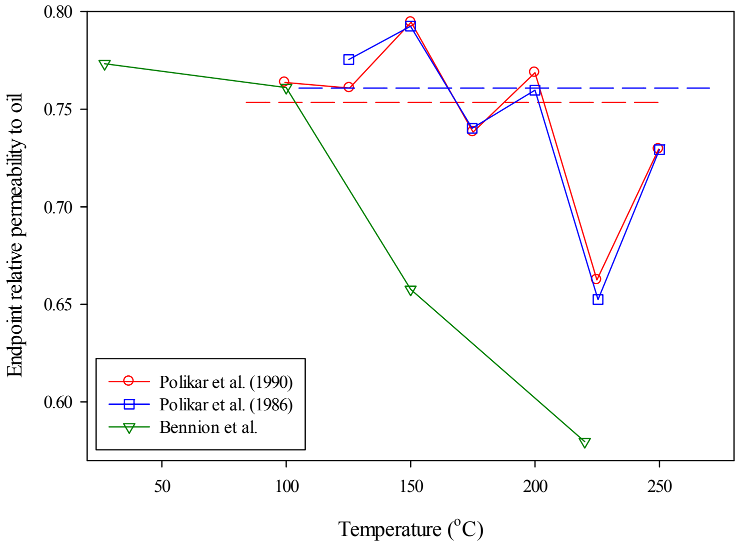

Figure 30. Different trends of oil endpoint relative permeability at higher temperatures [6, 7, 44].

Maini & Batycky [15] reported a decrease in k_{ro}^{0} with temperature in the range of 23 °C to 272 °C. In their work, fluctuations were seen in the trend of k_{ro}^{0} with temperature in horizontally drilled cores, especially at 150 °C. However, a clear trend was seen for vertically drilled cores. The endpoint declines in both horizontally drilled and vertically drilled plugs but the decline was more pronounced in the latter [15]. The reduction in absolute permeability of core as well as the increase in irreducible water saturation were suggested as a reason for this result. Moreover, it was mentioned that the difference between horizontally and vertically drilled cores in k_{ro}^{0} was caused by the occurrence of very thin shale layers, thin siderite-cemented sand beds and other aspects of the fluvial-meander-belt-type deposit [15].

Frizzell et al. [46] analyzed fifteen years of relative permeability measurements performed by Texaco's Exploration and Production Technology Division. This study investigated the effect of many factors (including temperature, absolute permeability and API gravity of oil) on residual oil saturation, irreducible water saturation, effective permeability to oil and water. Regarding the fluid properties and rock characteristics, crude oils and clean or restored unconsolidated sands were used in these measurements. The test temperature varied from 24 to 204 °C. It is notable that during all experiments, researchers [46] ensured that the injection rate followed the criteria proposed by Rapoport et al. [113] and they maintained the temperature constant in each test. Based on their correlation, a downward trend for oil relative permeability endpoint with increasing temperature is expected. The low value of the correlation coefficient of their correlation was attributed to the effect of various artifacts. For example, the cleaning procedure, using the same core in many experiments, different types of oil and effect of cyclically increasing temperature, using a solvent to clean the core could have caused scattered data [46]. The correlation for endpoint oil effective permeability is expressed as follow.

$$k_{ro}\left(S_{wi}\right)=\exp\Big[0.08974\times\left({}^{\circ}API\right)-0.00313\times\left({}^{\circ}F\right)+0.9561\times\ln\left(k_w\right)-0.0018\times\left(S_{wi}\right) \\ -4.461\times10^{-1}\Big] \tag{13}$$

here k_w is the absolute permeability to water in md and saturations are in percent.

In the study conducted by Bennion et al. [44], the temperature of the system was increased incrementally during four stages from 27 to 220 °C, so when no more oil was produced at a given temperature i.e. residual oil saturation was achieved, the temperature was increased to the next higher level [44]. According to the reported results, the endpoint effective permeability to oil declined with temperature from 0.591 μm^2 at 27 °C to 0.414 μm^2 at 220 °C. The values of k_{ro}^0 for the preserved core plug are shown in Figure 30.

Although many studies [12, 15, 17-19, 40, 44, 46] have indicated the declining trend of oil relative permeability endpoint with temperatures, Miller & Ramey [90], Kumar et al. [40] and Torabzadeh et al. [24] reported an increase in k_{ro}^0 at higher temperatures. In the study by Miller & Ramey [90], k_{ro}^0 failed to show any temperature dependency at early stages. However, the authors reported an interesting phenomenon when they shut down the test for about an hour after ending the experiments. Afterward, oil injection was restarted and the system was allowed to be stabilize. The results showed that by restarting oil injection, the relative permeability to oil phase was increased at irreducible water saturation [90]. The amount of such increase was larger at higher temperatures [90]. Note that prior to shutting down the system, some water droplet were periodically produced from the core outlet, while no water was drained from the core after oil reinjection. The redistribution of water phase, collected near the production end due to capillary end effect, caused this phenomenon during the shutdown period [90]. Miller & Ramey believed that this phenomenon will be enhanced as the fluid viscosity reduces at a higher temperature. This temperature dependency is illustrated in Figure 31.

Torabzadeh et al. [24] investigated the effect of temperature in systems with different IFT values. They indicated two different behavior of oil relative permeability endpoint with temperature changes, as shown in Figure 31. They stated that the effect of wettability change and IFT reduction at higher temperatures affected the endpoint in different directions.

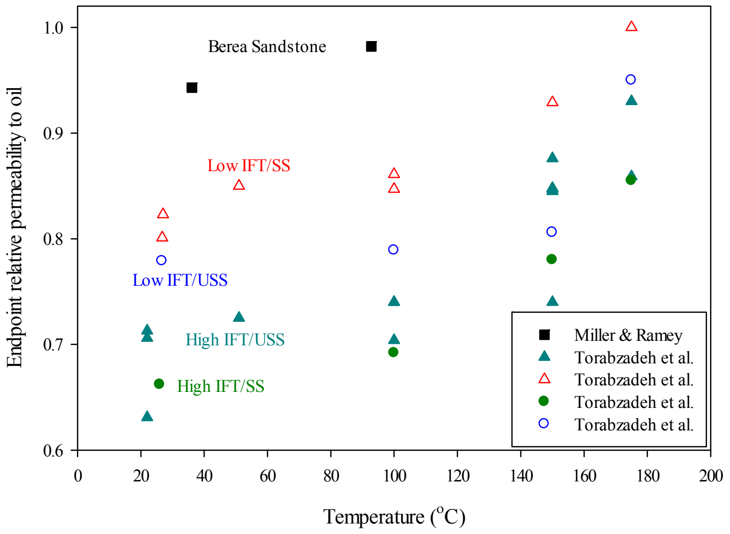

Figure 31. The variation of endpoint relative permeability to oil for different systems [24, 90].

Kumar et al. [40] developed empirical correlations to describe the temperature impact on relative permeability characteristics based on the results of Torabzadeh et al. [24]. It was postulated that for low tension system and high tension system, k_{ro}^{0} increased and decreased with temperature respectively [40]. The correlation developed for the oil endpoint relative permeability, which applies to both systems, is shown in Eq. (14).

$$k_{ro}\left(S_{wr}\right)=2.3136\times S_{wi}^{0.49684}\times S_{or}^{0.53469} \qquad (14)$$

The results generated by Ashrafi et al. [3], presented in Figure 32, show that the end point fluctuated with temperature. Hamouda et al. [22] found that there is an optimum temperature at which the highest endpoint can be achieved. However, Ashrafi et al. [3] did not completely agree with this observation. They found that the behavior of endpoint relative permeability was case dependent, which means that there might be an optimum temperature in some systems and not in others. Hamouda et al. [22] found that at temperature of 85 °C, the endpoint reached 1.0 and then decreased when temperature increased further. Some of the disagreement between these two studies is due to the use of different types of porous media, as Hamouda et al. [22] employed chalk cores and Ashrafi et al. [3] used glass beads. Figure 32 depicts all data presented in these two studies. Maini & Okazawa [8] and Nourmohammad et al. [48] concluded that the endpoint oil permeability was independent of temperature, and Akin et al. [37] stated that the temperature had little or no impact on the endpoint of relative permeability to oil. Kumar & Inouye [47] also demonstrated that endpoint relative permeability was temperature independent but it depended on the viscosity ratio.

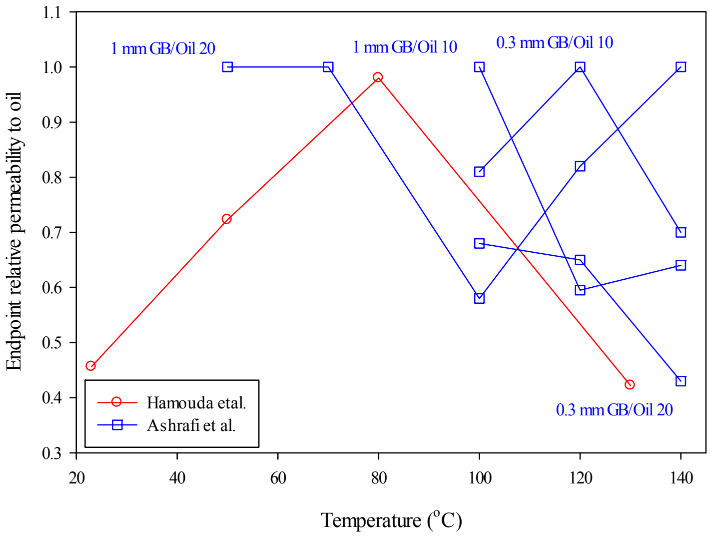

Figure 32. The changing in oil endpoint relative permeability at higher temperatures [3, 22].

Although, there are conflicting results in different systems, it appears that in majority of reported studies the endpoint relative permeability to oil was found to be independent of temperature. Therefore, unless reliable experimental information for a specific system shows a different trend, the endpoint relative permeability to oil should be assumed to remain unaffected by increasing temperature.

6.5. Shape of water relative permeability curve

Once the irreducible water saturation, the residual oil saturation, and the endpoint relative permeability to water are known, the only thing remaining to determine in water relative permeability is the shape of the curve. In some cases this shape can be quite complex and may include points of inflection. However, when the wettability is uniform and the pore size distribution is unimodal, the shape is expected to be relatively simple and it can be approximated by the following equation [104].

$$k_{rw} = k_{rw}^{0} \, (S_e)^{nw} \tag{15}$$

$$S_e = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \tag{16}$$

The effect of temperature on the shape can be described by examining how the value of the exponent (*nw*) changes with temperature. This requires fitting the above equation to each reported relative permeability curve to determine the exponent (*nw*), unless the exponent value was already reported in the paper [4, 17]. This was done for the reviewed studies that reported a significant effect of temperature on water relative permeability. In some cases the fitted values of exponents were very large (greater than 6) or negative and these were considered outliers and discarded. The remaining values are plotted against the temperature in Figure 33. It is apparent that there is no easily discernable trend in this data. The linear regression line shows a small increase in *nw* with temperature starting from a value of 2.0 at the ambient temperature, but with very poor correlation coefficient. Therefore, it can be suggested that in the absence of reliably measured values, the shape of water relative permeability should be considered independent of temperature.

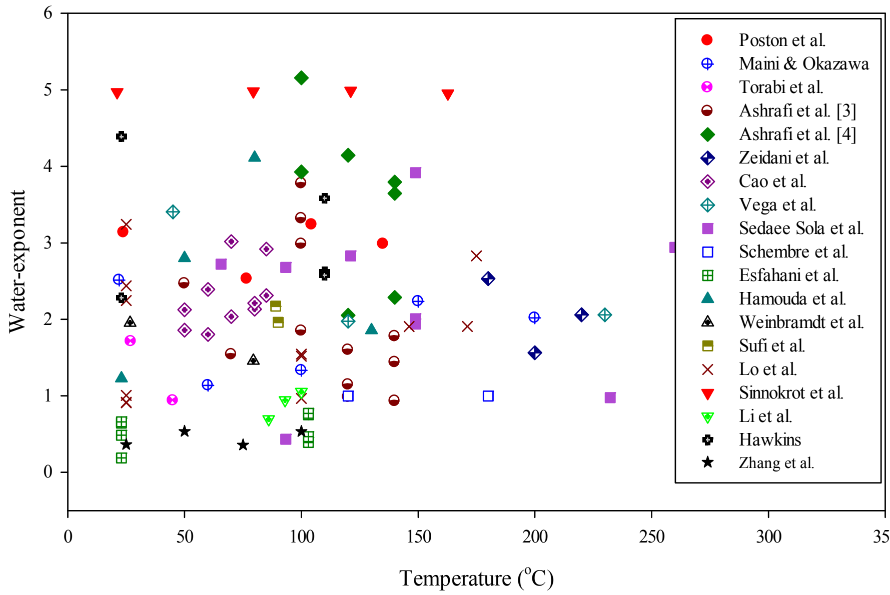

Figure 33. The effect of temperature on exponent of water relative permeability.

6.6. Shape of oil relative permeability curve

The shape of oil relative permeability was examined the same way as water relative permeability curve discussed above. In majority of the reported cases, it can be approximated by the following equation [104].

$$k_{ro} = k_{ro}^{0}\,(1 - S_e)^{no} \qquad (17)$$

The effect of temperature on the shape of relative permeability curve was examined by determining how the best fit value of the exponent (*no*) changes with temperature. This required fitting Eq. (17) to the reported relative permeability curves in studies that did not directly report the value of the exponents. The results are shown in Figure 34. The exponent values higher than 6 and negative exponents were again considered outliers and discarded. The values show no clear-cut trend with increasing temperature. Therefore, we conclude that in the absence of reliable experimental data for the system of interest, the shape of oil relative permeability should also be considered independent of temperature.

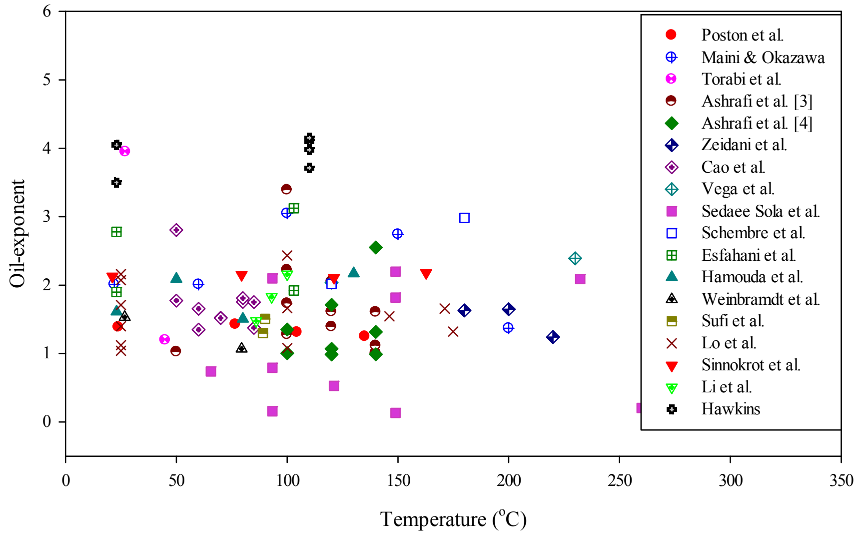

Figure 34. The effect of temperature on exponent of oil relative permeability.

6.7. Discussion

Both steady-state and unsteady-state measurements suffer from experimental artifacts to varying degrees. In steady-state tests, the principal sources of experimental errors are capillary end-effects and uncertainties in saturation measurements. Large volumes of fluid injection are needed to achieve the steady-state condition at each setting, which makes the determination of saturation by material balance unreliable. In-situ saturation measurements of different type have their own artifacts. However, the steady-state measurements with a reliable in-situ saturation measurement technique would be relatively less prone to experimental artifacts. In unsteady-state measurements, the artifacts include difficulties in maintaining accurate material balance to determine the saturations, capillary end effects at the production end, premature termination of the test before reaching close to the end-point saturation, and differences in the methodology used to infer relative permeability from displacement data.

The problem of viscous fingering in displacement tests is a source of error in many studies. As stated earlier, the relative permeability is a useful function of saturation only when capillary forces control the fluid distribution within the pore-space. This requires running the displacement tests under conditions that will ensure a stable displacement, which often translates to using gravity stable displacements at very low flow velocity. However, the need to minimize the capillary end effects requires higher velocity displacements and in viscous oil systems, these two conflicting requirements are difficult to reconcile.

Rapoport and Leas [113], and Peters and Flock [114] developed a scaling factor and a dimensionless number respectively, which are useful in assessing the impact of capillary end effects and viscous fingering in displacement tests. The effect of the scaling coefficient introduced by Rapoport and Leas [113] on oil recovery at breakthrough time is shown in Figure 35. The oil recovery is independent of the scaling coefficient, when its value is above 3.5 cm^2.cP/min. The Peters and Flock dimensionless number [114] is expressed in Eq. (18) through Eq. (20). As shown in Figure 36, the unstable region consists of a transition zone, which occurs, in the dimensionless number range of 13.56 and 1000. Therefore, a stable displacement occurs when this factor is below 13.56. Note that the wettability number used in Eq. (18) is taken to be 5.45 for the oil-wet media and 306.25 for the water-wet porous media [114].

$$I_{sc} = \frac{(M-1)\left(v^* - v_c\right)\mu_w D^2}{C^* k_{wor}\sigma} \tag{18}$$

$$v_c = \frac{k_{wor}\left(\rho_w - \rho_o\right) g \cos\alpha}{\mu_w (M-1)} \tag{19}$$

$$M = \frac{\mu_o k_{wor}}{\mu_w k_{oir}} \tag{20}$$

Only a small number of researchers paid attention to these numbers and ensured that viscous fingering and capillary end effects did not affect their results. Often description of experimental conditions is missing some of the parameters needed to calculate these numbers. In majority of the reported studies, flow velocity appears to be high enough to satisfy the scaling coefficient of Rapoport and Leas [113] but in most of the displacements with viscous oils, the stability number appears to be too high to ensure a stable displacement. Table 5 shows the fluid flow velocity, injection flow rate or the viscous stability numbers reported in some studies.

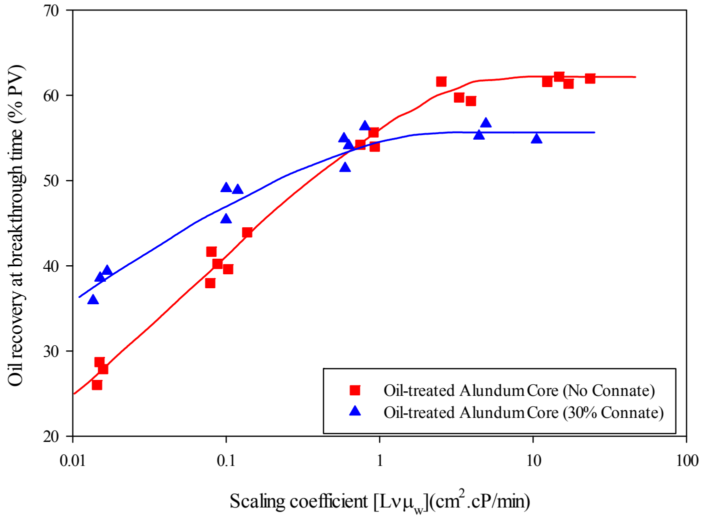

Figure 35. The recovery factor as function of the scaling coefficient at the breakthrough time [113].

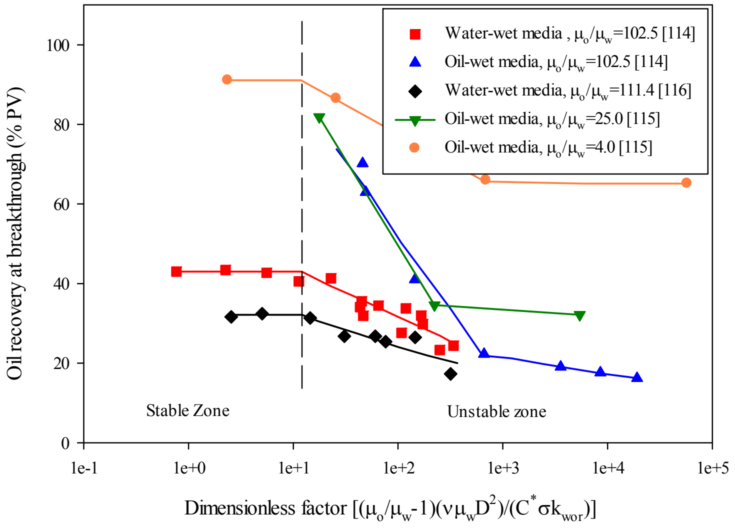

Figure 36. Recovery data versus the dimensionless parameter from the literature [114-116].

Finally, it is unreasonable to expect that the effect of temperature on oil-water relative permeability would be same in all rock-fluid systems. The impact of temperature arises from temperature-induced changes in wettability, interfacial tension and possibly pore geometry, although the latter is not a factor in many systems. These changes depend on the initial wettability condition and the mineral composition of the rock and the chemical composition of the fluids. Generally, increased temperature reduces adsorption of species on rock surfaces and if the initial wettability were influenced by adsorption of polar organic components, there would be a stronger possibility of a change in wettability with increase in temperature. The effect of temperature on interfacial tension will also be different depending on the composition of the oil and brine. Therefore, it is not advisable to generalize the effect of temperature on oil-water relative permeability.

Table 5. The value of fluid flow velocity or injection flow rate reported in the reviewed studies.

Fluid flow velocity or injection Flow rate					
Researcher	**Year**	**Value**	**Researcher**	**Year**	**Value**
Wilson [86]	1956	0.0026-0.78 cc/min (ID=2.587 cm)	Edmondson [21]	1965	7 cc/min (ID=5.09 cm)
Weinbrandt et al. [20]	1975	0.359- 0.891 cc/min	Amaefule and Handy [89]	1982	2.0 cc/min (CA=5.07 cm^2)
Sufi et al. [51]	1982	6.67 cc/min (ID=2.54 cm)	Torabzadeh et al. [24]	1984	0.5-3.0 cc/min (ID=2.54 cm)
Polikar et al. [7]	1986	0.9 PV/hr	Watson and Ertekinb[19]	1988	3.33 cc/min (ID=5.08 cm)
Closemann et al. [84]	1988	0-0.188 cc/min	Hawkins [91]	1989	2.0-10.0 cc/min
Polikar et al. [6]	1990	6.6 ft/day (1 PV/hr)	Kumar and Inouye [47]	1994	3 cc/min (ID=5.08 cm)
Siddiqui et al. [92]	1999	1.67 cc/min	Wang et al. [52]	2006	0.167 cc/min

					(ID=4.25 cm)
Sedaee Sola et al. [17]	2007	KM: 0.003-0.557 PY: 0.2-0.333 cc/min (ID=3.83 cm)	Ashrafi et al. [3]	2012	0.8-0.1cc/min (ID=3.8 cm)
Akhlaghinia et al. [2]	2013	0.1 cc/min (ID= 2.54 cm)	Vang et al. [18]	2014	0.003-0.05 cc/min (ID=2.54 cm)
Ashrafi et al. [4]	2014	0.5 cc/min (oil) 0.8 cc/min (water) (ID=3.8 cm)	Cao et al. [45]	2014	0.1 cc/min (oil) 0.1-0.5 cc/min (Water) (ID=2.427-2.518 cm)
Nourmohammad et al. [48]	2015	9 cc/min (ID=3.81 cm)	Zhang et al. [25]	2017	0.1 cc/min (ID=2.452-2.550 cm)
Torabi et al. [42]	2015	0.2-0.4 cc/min			

7. CONCLUSIONS

The preceding review of previous studies shows that in spite of numerous investigations spanning over half a century, the issue of temperature's impact on oil-water relative permeability is still not fully resolved. New findings are still being reported on this topic [117]. There appear to be three reasons for the lack of consensus in experimentally observed results:

(1) The measurements of relative permeability at high temperature are complex and often the reported results include experimental artifacts.

(2) Meaningful relative permeability measurements require that capillary forces control the fluid distribution within the pore space, but this condition is difficult to ensure in viscous oil systems.

(3) The impact of temperature is not same in all rock-fluid systems, it depends on how the wettability, interfacial tension and sometimes even the pore geometry changes with temperature.

In reservoir systems that have a higher potential for temperature effect, it would be advisable to obtain experimental measurements. These should include not only relative permeability tests but also measurements of wettability and interfacial tensions. Without such experimental measurements, it might be just as good to assume that the relative permeability is independent of temperature as to assume that it will move with temperature in a predictable manner.

ACKNOWLEDGEMENT

The financial support for this work was provided by NSERC/Nexen and CNOOC Industrial Research Chair in Advanced In-Situ Recovery Processes for Oil Sands program and University of Calgary's Global Research Initiative in Sustainable Low Carbon Unconventional Resources, funded from the Canada First Research Excellence Fund.

NOMENCLATURE

C^*	Wettability number	D	Core diameter
g	Gravitational acceleration	k_{ro}	Relative permeability to oil
k_w	Absolute permeability to water	k_{ri}	Relative permeability to ith phase
k_{wor}	Water relative permeability endpoint	k_{abs}	Absolute permeability
k_{ei}	Effective permeability to ith phase	k_{ro}^0	Oil relative permeability endpoint
k_{oir}	Oil relative permeability endpoint	k_{rw}^0	Water relative permeability endpoint
L	Core length	M	Mobility ratio
N_c	Capillary number	nw	Water exponent
no	Oil exponent	S_w	Water saturation
S_{or}	Residual oil saturation	S_e	Normalized water saturation

S_{wi}	Irreducible water saturation	S_i	ith phase saturation
T	Temperature	V	Fluid velocity

Greek symbols

α	Angle core makes with the vertical	μ	Displacing fluid viscosity
μ_w	Water viscosity	μ_o	Oil viscosity
v^*	Constant superficial velocity	v	Fluid velocity
v_c	Characteristic velocity	ρ_o	Oil density
ρ_w	Water density	σ	Interfacial tension
θ	Contact angle		

Abbreviation

CA	Cross section area	**CSS**	Cyclic steam stimulation
ID	Inner diameter	**IFT**	Interfacial tension
N/A	Information not available	**PV**	Pore volume
ROS	Residual oil saturation	**SAGD**	Steam assisted gravity drainage
SARA	Saturate-Aromatic-Resin-Asphaltene		

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