Review

Can Effects of Temperature on Two-Phase Gas/Oil-Relative Permeabilities in Porous Media Be Ignored? A Critical Analysis

Saket Kumar , Sajjad Esmaeili, Hemanta Sarma * and Brij Maini

Department of Chemical and Petroleum Engineering, University of Calgary, Calgary, AB T2N 1N4, Canada; saket.kumar1@ucalgary.ca (S.K.); sajjad.esmaeili1@ucalgary.ca (S.E.); bmaini@ucalgary.ca (B.M.)

* Correspondence: hemanta.sarma@ucalgary.ca; Tel.: +1-403-220-3065

Received: 21 May 2020; Accepted: 30 June 2020; Published: 3 July 2020

Abstract: Thermal recovery processes for heavy oil exploitation involve three-phase flow at elevated temperatures. The mathematical modeling of such processes necessitates the account of changes in the rock–fluid system’s flow behavior as the temperature rises. To this end, numerous studies on effects of the temperature on relative permeabilities have been reported in the literature. Compared to studies on the temperature effects on oil/water-relative permeabilities, studies (and hence, data) on gas/oil-relative permeabilities are limited. However, the role of temperature on both gas/oil and oil/water-relative permeabilities has been a topic of much discussion, contradiction and debate. The jury is still out, without a consensus, with several contradictory hypotheses, even for the limited number of studies on gas/oil-relative permeabilities. This study presents a critical analysis of studies on gas/oil-relative permeabilities as reported in the literature, and puts forward an undeniable argument that the temperature does indeed impact gas/oil-relative permeabilities and the other fluid–fluid properties contributing to flow in the reservoir, particularly in a thermal recovery process. It further concludes that such thermal effects on relative permeabilities must be accounted for, properly and adequately, in reservoir simulation studies using numerical models. The paper presents a review of most cited studies since the 1940s and identifies the possible primary causes that contribute to contradictory results among them, such as differences in experimental methodologies, experimental difficulties in flow data acquisition, impact of flow instabilities during flooding, and the differences in the specific impact of temperature on different rock–fluid systems. We first examined the experimental techniques used in measurements of oil/gas-relative permeabilities and identified the challenges involved in obtaining reliable results. Then, the effect of temperature on other rock–fluid properties that may affect the relative permeability was examined. Finally, we assessed the effect of temperature on parameters that characterized the two-phase oil/gas-relative permeability data, including the irreducible water saturation, residual oil saturation and critical gas saturation. Through this critical review of the existing literature on the effect of temperature on gas/oil-relative permeabilities, we conclude that it is an important area that suffers profoundly from a lack of a comprehensive understanding of the degree and extent of how the temperature affects relative permeabilities in thermal recovery processes, and therefore, it is an area that needs further focused research to address various contradictory hypotheses and to describe the flow in the reservoir more reliably.

Keywords: relative permeability; gas/liquid systems; effect of temperature; flow in porous media; thermal recovery method

1. Introduction

The most commonly employed Enhanced Oil Recovery (EOR) techniques for heavy oil reservoir are thermal methods such as Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation

(CSS), and steam flooding, with the common key objective to improve the oil mobility through viscosity reduction using heat [1,2]. Therefore, thermal methods are characterized by their high temperature [3]. The increase in temperature may significantly affect the properties of the reservoir rock and fluids; for example, pore geometry can be changed with the rise in temperature, which, in turn, can affect the fluid distribution and the flow performance [4–6]. The fluid properties such as density and viscosity, as well as the fluid/fluid and rock/fluid interaction characteristics, such as wettability and interfacial/surface tension would also change with temperature. Hence, the relative permeabilities to different fluids present in porous media representing the fluid flow behavior are likely to change with the temperature. We also need to consider the steam flow in the rock, as the application of heat (through the injected steam) leads to a three-phase flow of oil, water and steam. The flow of steam comprising both the injected and in situ generated steam due to the heat mimics the gaseous phase. Therefore, it is envisaged that both steam/oil-relative permeabilities alongside water/oil-relative permeabilities control the flow during steam injection processes. In addition, we also need to account for the other effects such as change in rock and fluid properties with temperature [7] in the modeling of a thermal recovery process.

An issue arises in measuring the absolute permeability with gas at a low-pressure because of the slippage effect, which makes the absolute permeability measured with gas larger than what it could be with a liquid, as described by Klinkenberg [8]. However, Klinkenberg suggested that the gas slippage at the surface of the pore throats can be neglected if the pore size is large enough compared with the mean free path of gas molecules. With this assumption, the measured absolute permeability to gas can be similar to the measured absolute permeability to liquids [8–10]. This will make the slippage effect is more pronounced in pore-throats smaller in size or low-permeable reservoirs such as shale and tight gas/oil formations [9,10].

The knowledge of two-phase gas/oil-relative permeability is essential in predicting the fluid flow behavior and the ultimate oil recovery in thermal recovery processes [11,12]. The relative permeability characteristics are also formation-type dependent; they change from one formation to another due to the variation in the characteristics of the reservoir such as pore geometry, composition, lithology, pore size distribution, and fluid/rock or fluid/fluid interactions [11]. As stated earlier, when the temperature increases, the fluid flow behavior may be altered by changes in one or more petrophysical characteristics.

Compared to the oil/water system, only a few studies for the effect of temperature on rock–fluid characteristics in gas/oil systems have been reported [6,13–17]. Most have argued that temperature's impact on gas/oil systems was quite similar to that experienced in the water/oil systems. Table 1 summarizes some of the key results on the effect of temperature on two-phase-relative permeabilities for gas/oil systems.

Table 1. Summary of the reported studies on the effect of temperature on gas/liquid-relative permeability.

Authors	Year	Measurement Techniques	Porous Media	Type of System	Temperature Range (°C)	Effect of Temperature on Relative Permeability
Longeron [15]	1980	Unsteady-state	Core	Oil/Gas	20–71	k_r of both phases increased
Berry et al. [14]	1992	Unsteady-state	Core	Oil/Gas	Ambient to 93	k_{ro} increased and k_{rg} was independent
Muqem (Ph.D. Thesis) [17]	1994	Unsteady-state	Core	Oil/Gas	75–125	k_{ro} has been increased but k_{rg} was not affected
Akhlaghinia et al. [13]	2014	Unsteady-state	Sand pack	Oil/CH ₄ gas	28–52	k_{rg} increased but k_{ro} decreased from 28 to 40 °C and then increased dramatically above 40 °C
Akhlaghinia et al. [13]	2014	Unsteady-state	Sand pack	Oil/CO ₂ gas	28–52	k_{rg} increased but k_{ro} decreased from 28 to 40 °C and then increased dramatically above 40 °C
Punase et al. [6]	2014	N/R	N/R	Oil/Gas	Not Reported	Both phases affected with temperature when wettability changed
Modaresghazani (Ph.D. Thesis) [16]	2015	Steady- and unsteady-state	Sand pack	Oil/Gas	Not Reported	Both k_{ro} and k_{rg} were affected

In this paper, the techniques that have been utilized to measure the two-phase gas/oil-relative permeability are reviewed. Additionally, experimental artifacts, possible errors and the results of published articles are discussed for two-phase gas/oil-relative permeability. Furthermore, various

rock–fluid properties, including the wettability, capillary end effect, surface tension, viscosity ratio, and saturation history on two-phase gas/oil-relative permeability, were reported in the literature, are assessed.

2. Fundamentals

All naturally-occurring porous media are anisotropic and exhibit a pore size distribution, meaning pore channels are more non-uniformly conducive to fluid flow primarily because of the variation of sizes, orientations and network configuration. Therefore, the conductivity of the medium to a particular fluid cannot simply be proportional to its saturation only but will also depend on whether it occupies more or less conductive channels and the presence of other fluids.

Essentially, gravity, viscous and capillary forces act together and control the fluid flow and distribution in porous media. However, the capillary forces resulting from the wettability and surface tension (ST) dominate other forces, acting as the trapping force, especially at low flow velocities; i.e., when the capillary force primarily controls the fluid distribution and interfaces in porous media. In water-wet systems, the water adheres to the rock surface and preferentially occupies small pores; whereas, the oil tends to remain in the center of the pore space. Since the relative permeability to a particular fluid depends on which portion of pore space is occupied by it, and this distribution is controlled by capillarity, the relative permeability becomes a determinable function of fluid saturation [18]. It should be understood that any deviation from the capillary-controlled fluid distribution condition can make the relative permeability dependent on other factors (such as wettability, surface tension, viscosity of the fluid phase, i.e., gas and liquid, and temperature) than fluid saturation [19].

The gas/oil-relative permeability curves, in the presence of irreducible water saturation, require at least seven parameters to be characterized, including the irreducible water saturation, residual oil saturation, critical gas saturation, oil endpoint-relative permeability, gas endpoint-relative permeability, and other remaining two parameters being the characteristic shapes of the two curves (known as the oil and gas-relative permeability exponents). The significance of these seven factors is described in the following prior to discussing the effect of temperature on gas/oil-relative permeability curves.

2.1. Irreducible Water, Residual Oil, Critical Gas, and Liquid Saturation

The critical saturation of any fluid is defined as the minimum saturation below which the it cannot flow in the porous medium; for example, if the gas phase gradually appears in the oil-filled system, the gas cannot start flowing until it reaches a threshold saturation, called the critical gas saturation [20]. Consequently, the gas-relative permeability at any saturation lower than or equal to the critical saturation remains zero. The oil residual saturation concept is similar to critical gas saturation but we normally approach it from the opposite end (i.e., starting with a high oil saturation and then decreasing it until the oil stops flowing) [21]. The relative permeability to oil is zero at any saturation lower than or equal to the residual oil saturation. Irreducible water saturation in porous media is defined as the saturation of water below which water cannot flow. The relative permeability to water at any saturation below or equal to the irreducible water saturation remains zero [22].

Esmaeili et al. [19] have discussed how the fluids (gas, oil and water) are distributed in porous media. The residual saturation of the non-wetting phase remain trapped as isolated blobs due to capillary force [11,23]. However, the residual saturation of the wetting phase remains as a continuous thin film on the pore wall, because it adheres to the rock surface; however, the phase mobility becomes practically zero at the residual saturation.

2.2. Endpoint-Relative Permeability to Oil and Gas

Endpoint-relative permeability to any phase is the maximum value of the relative permeability to that phase which is attained at its maximum saturation [23]; for example, endpoint-relative permeability to oil, in the presence of irreducible water saturation, is the maximum value of oil-relative permeability

at the critical gas saturation, and endpoint-relative permeability to gas is the highest value of gas-relative permeability at residual oil saturation, where gas saturation is maximum.

2.3. Shapes of Oil and Gas Relative Permeability Curves

Gas/oil-relative permeability is always reported either as a function of gas saturation or oil saturation. However, when the irreducible water is present in the system, the gas/oil-relative permeability can be considered as a function of liquid saturation representing the summation of oil and water saturation. Typical curves of gas/liquid-relative permeability are shown in Figure 1. The increase in relative permeability to any phase, between its critical and maximum saturation, is the result of more flow channels becoming available for its flow.

Figure 1. Typical curve of gas/liquid-relative permeability [7].

3. Techniques for Measuring Gas/Oil-Relative Permeability

The two-phase gas/oil-relative permeability of a porous medium can be estimated in various ways: fluid–fluid displacement tests, empirical correlations, numerical modeling, and using available analogs [7]. Laboratory methods for measuring two-phase gas/oil-relative permeability include the steady-state, unsteady-state, centrifuge, and capillary pressure measurement techniques [21]. This review mainly focusses on the steady-state and unsteady-state techniques and relevant details for other techniques can be found elsewhere [19,24].

3.1. Steady-State Approach

In the steady-state technique, pressure drop and production rates are monitored at a constant injection rate for both fluids (gas and oil) until the flow characteristics, i.e., pressure drop and produced fluid flow rate, become time-independent. The same type of measurement is repeated using several combinations of flow rates to determine the full relative permeability curves. The technique is time-consuming because the steady-state has to be attained before a datapoint can be obtained. In addition, it is also subject to significant capillary-end effects if due precautions are not taken at the inlet and outlet ends.

3.2. Unsteady-State Approach

In the unsteady-state technique, known as the displacement method or external-drive method, an immiscible fluid is injected at a constant injection rate into the core sample or sand pack to displace the resident fluid [21]. In gas/oil systems, the gas (the non-wetting phase) may be used as displacing

fluid, and the oil (most likely the wetting phase) may act as the displaced fluid. This method takes considerably less time than the steady-state approach [25] but provides the relative permeability data for only the post-breakthrough period. Typical unsteady-state-relative permeabilities are the ones we normally compute from the laboratory coreflood tests and this method mimics the dynamic flow conditions in the porous medium during displacements. Figure 2 shows a conceptual depiction of the difference in procedures adopted in the two methods.

Figure 2. Conceptual depiction of experimental procedures in gas/oil steady- and unsteady-state-relative permeability measuring techniques.

4. Challenges in Measuring Gas/Liquid-Relative Permeability

4.1. Gas Slippage Effect

Gas/oil two-phase-relative permeabilities are an important input parameter in numerical simulation studies for thermal recovery processes. There may be a considerable effect of gas slippage in gas/oil two-phase flow through the pore/throat network at low pressures, which could eventually affect their relative permeabilities and this has been noted by several authors [8,26–32].

Rose [33] conducted an experimental study to measure the two-phase gas/water-relative permeability curve in a sandstone core, and reported that the slip factor decreased with an increase in the liquid (water) saturation. However, the liquid saturation was not uniformly distributed in his study, which could be the reason for erroneous results. Moreover, it is a challenge to measure gas-relative permeability at high liquid saturations (say, above 50%) by allowing only gas to flow while keeping the water immobile. Fulton [28], based on his measurements in the limited range of 0 to 30% of liquid saturation, made the same observation as Rose [33] and reported that with an increase in liquid saturation, the slip factor decreased. Later, Estes and Fulton [27] extended this study by changing the liquid phase to oil (Soltrol), instead of water. They varied the liquid saturation between 30% and 88%, and their observations were also similar to those by Rose [33] and Fulton [28]. Sampath and Keighin [31] also asserted that an increase in liquid saturation caused a reduction in the gas slip factor in their work, which is contradictory to the assumptions of Klinkenberg's theory gas slippage effect [31], incorporated in the following Klinkenberg equation [8]:

$$k_g = k_g^\infty \left(1 + \frac{4c\gamma}{r} \right) \quad (1)$$

where k_g is the absolute permeability of rock measured with gas at the mean pressure p_m (the arithmetic average of the outlet and inlet pressure of the porous medium), and k_g^∞ denotes as the absolute or intrinsic permeability to gas at an infinite pressure, c is the proportionality factor which is less than 1; γ is the mean free path of the gas and r is the average size of the capillaries. Since the mean free path is proportional to the mean pressure, Klinkenberg [8] reduced the equation to:

$$k_g = k_g^\infty \left(1 + \frac{b}{p_m} \right) \quad (2)$$

where b is the slip factor and is described as:

$$b = \left(\frac{4c\gamma p_m}{r} \right) \quad (3)$$

The gas slippage factor is inversely proportional to the radius of capillaries [8]. On the other side, the gas slippage factor can be increased if the effective pore radius is reduced due to the accumulation of liquid phases in pores. Thus, the assumption of Klinkenberg [8] that b was inversely proportional to the radius of the capillary at constant mean pressure was confounded in studies by several other researchers [27,28,31,33]. The capillary radius of the porous media could not be changed without variation in the stress regime, which results in a change in the inner structure of the pores, other than an effective radius for the capillary for gas. However, Equation (3) also suggests that if the radius of the capillary and other parameters (i.e., mean free path) remain constant, the slip factor becomes directly proportional to the mean pressure, which was also assumed to be constant in Klinkenberg's [8] hypothesis. Thus, the experimental results presented by Estes and Fulton [27] have shown the reduction in slip factor due to a decrease in the mean pressure, not because of the radius of the capillary at every specific liquid saturation. Therefore, the change in the effective radius of the capillary for gas due to variation in mean pressure resulted in the decrease of slip factor. This is not appropriate, as per the Klinkenberg's [8] hypothesis. Some issues pertinent to the study of gas slippage in two-phase flow [8,27,31] still remain unresolved due to the use of small-size cores and the method employed for establishing the liquid saturation.

Mahiya [30] reported that the gas absolute permeability, k_g , at low mean pressure was greater than the absolute liquid permeability (k) due to the gas slippage effect. If the gas slippage effect is significant, the relative permeability to gas at low pressures can yield a value greater than one at some water saturations. The X-ray method was utilized in his work for measurement of the saturation profile [30]. Counsil [26] suggested that the gas slippage effect may be neglected when the gas/liquid-relative permeability measurements were carried out under high-pressure and high-temperature (HP-HT) conditions. The complication involved in running experiments during HP-HT conditions was measuring the water saturation in the core while using the X-ray CT technique. However, Wei et al. [32] illustrated, from their study, that the slip factor (b) might increase at higher temperatures, which could ultimately influence the gas slippage on the gas flow properties. The capillary end effect due to the capillary discontinuity can have a significant effect on the distribution of liquid saturation in small cores. Rose (1948) established the liquid saturation in their experiment by an evaporation process, Fulton [28] on the other hand, used two different methods to establish the liquid saturation; the first was the same as Rose [33] (i.e., by the evaporation process), and the other was the water imbibition [28].

To understand the effects of temperature on gas-relative permeability in two-phase flow, Li and Horne [29] conducted a number of experiments at the several temperatures up to 120 °C. They used a long Berea sandstone core to overcome the capillary end-effects. The core had the permeability and porosity of 1280 mD and 23.1%, respectively. They assumed that gas permeability was not only a function of mean pressure, but it also depended on the liquid saturation. They observed that the effective (or apparent) gas permeability increased with an increase in temperature. However, the absolute permeability measured with gas at the infinite mean pressure was observed to be equal at different temperatures. As per a few authors [8,26–33], the effect of liquid saturation on the slippage effect in gas/liquid two-phase flow remains controversial and has been a subject of much debate. Some researchers [8,27,31] found that the slip factor decreased by an increase in liquid saturation, while others [26,30,32] have reported and argued for the opposite trend.

4.2. Measurement Challenges

Measurements of gas/liquid-relative permeabilities in heavy oil systems have received very little attention in the literature [34] even though such data are needed for reservoir modeling studies, especially for thermal recovery processes. The two-phase gas/oil-relative permeability

is usually measured at the irreducible water saturation when the mobility of water phase is negligible. The same techniques that are used for oil/water-relative permeability measurements can be used for gas–liquid-relative permeability. In addition, oil/gas-relative permeability can also be inferred from solution gas drive (also known as an internal gas drive) tests [34]. The experimental difficulties involved in heavy oil/gas-relative permeability measurement are somewhat more severe compared with the oil/water case. The mobility ratio is even more adverse in such displacement tests involving the gas injection which causes viscous fingering of the gas [35,36]. The solution gas-drive in heavy oil systems can generate foamy oil flow, which makes the inferred gas/oil-relative permeability sensitive to depletion rate.

Another complication stems from the possibility of significant mass transfer across the gas/liquid interface [34] and at HT-HP reservoir conditions most gases develop an increased solubility in oil and water [37]. Therefore, unless the oil and water present in the core are already saturated with the same gas, some of the injected gas will dissolve into the liquid phases [21]. On the other hand, unless the gas phase is pre-equilibrated with water and oil, it can cause evaporation of water or light components from the oil. If there is a large pressure drop over the length of the core, pre-equilibration at the inlet condition cannot totally prevent evaporation near the outlet end.

In addition to the above challenges in measuring relative permeability, many rock–fluid interactions such as wettability and surface tension or even fluid properties such as viscosity ratio might also affect the gas/oil two-phase-relative permeability.

5. Effect of Temperature on Rock/Fluid Interactions and Properties

As the temperature of porous media is increased, both the rock and fluid properties can change significantly. In this section, we examine the effect of temperature on fluid–fluid (surface tension) and rock–fluid (wettability) interactions, and fluid property (viscosity ratio) which can have substantial effect on two-phase gas/liquid-relative permeability.

5.1. Surface Tension

Several studies [38–44] have addressed the functionality of relative permeability to surface tension through laboratory experiments. Additionally, many researchers reported that surface tension tends to decrease with increasing temperature [39–42,44]. On the contrary, a few researchers have reported that with an increase in temperature, the surface tension also increases [38,43]. However, to isolate the effect of temperature-induced surface tension on relative permeability from other affecting parameters, it is necessary to find other ways to change the surface tension, without altering additional affected parameters, such as, the viscosity ratio, which is even more temperature-sensitive [40]. Theoretically, the surface tension between liquid and gas are dependent on both the pressure and temperature [45].

Initially, Longeron [15] reported this by evaluating the effect of surface tension on gas/liquid-relative permeability at the constant temperature of 71.1 °C with varying pressure. A 38.2-cm long Fontainebleau sandstone core with a diameter of 5 cm was used in the experiments performed by Longeron [15] with methane and hexane as the gas and liquid phases, respectively. Mineralogically, the Fontainebleau sandstone used was composed of pure silica with very homogenous grain size. To understand the mechanics of the effect of surface tension on gas/oil-relative permeability, Longeron conducted his experiments in a steady-state condition in the absence of irreducible water saturation by injecting gas into a fully oil-saturated core plug. In addition to being a time-consuming method, the other challenge he faced with the steady-state process was the difficulty to indirectly measure the saturation and volume of fluids at the high-temperature condition. He found that with an increase in pressure from 2.76 MPa to 24.27 MPa, the surface tension reduced from 12.62 mN/m to 0.0047 mN/m, which resulted in the reduction of residual oil saturation (from 0.35 to almost zero), accompanied by a linear increase in both oil- and gas-relative permeabilities. Further analysis revealed that the major change in the relative permeability curve seemed to occur in the vicinity of surface tension equal to 0.04 mN/m and the relative permeability curves tended towards straight lines as surface tension approached

0.001 mN/m. It was reported by Longeron that an increase in the miscibility of methane in hexane might have affected the surface tension.

Fulcher et al. [46] and Harbert [47] indicated that relative permeability curves were significantly influenced by surface tension values less than 2 mN/m. They reported the effect of surface tension on relative permeability curves and endpoint saturations in terms of capillary number. Later, Asar and Handy [48] performed a similar study as Longeron [15] using a highly volatile methane/propane system to measure steady-state gas/liquid-relative permeability as the function of surface tension and observed the similar effect [48]. Later, Cai et al. [38] postulated the weak dependency of surface tension on pressure, in that the surface tension reduced from 51.73 to 51 mN/m with a reduction in pressure from 2.07 to 0.25 MPa. They also asserted that compared to pressure, temperature had a much stronger impact on the surface tension and they noted that the surface tension was reduced when the temperature increased from 25 to 50 °C.

Honarvar et al. [49] reported that the gas/liquid-relative permeability was affected by surface tension in their experiments. In addition to the effect of surface tension on gas/liquid-relative permeability, they also reported that surface tension decreased from 16.80 to 10.37 mN/m as the temperature was raised from 40 to 100 °C [49]. This downward variation in surface tension was also attributed to the CO₂ solubility in brine at higher temperatures of their study. Few other researchers [43,44] have also expressed the similar observations such as Longeron [15], Maini and Batycky [40], Polikar et al. [41], Asar and Handy [48], and Honarvar et al. [49] that surface tension was a strong function of both temperature and pressure. They postulated that an increase in pressure led to a reduction in surface tension between gas and liquid, as well as for the liquid–liquid systems. In addition to the pressure dependency, they also ascertained that the increase in temperature caused the surface tension to increase which was contradictory to the findings of Polikar et al. [42] and Honarvar et al. [49]. Yang et al. [50] attempted to understand the effect of pressure and temperature on surface tension for CO₂/Brine and CO₂/Crude oil systems under varying test conditions of the pressure and temperature in range of 0.11–16.11 MPa and 27–58 °C, respectively. They observed that surface tension decreased from 29 to 1.12 mN/m for CO₂/Brine and 27 to 1.5 mN/m for CO₂/Crude oil system as pressure increased at the constant temperature. The surface tension for CO₂/Brine was decreased from 28.4 to 27.2 mN/m when the temperature was increased. Yang et al. [50] also reported that the surface tension was increased with increase in temperature at constant pressure in their CO₂/Crude oil system which was not in good agreement with Cai et al. [38]. Chalbaud et al. [51] extended the work performed by Yang et al. [50] and measured the surface tension of CO₂/brine systems at varying temperatures from 27 to 71 °C and finally to 100 °C. They concluded that the surface tension for CO₂/brine system was increased with the increasing temperature which was not in agreement with Yang et al.'s findings.

Bachu and Bennion [37] conducted several experiments using CO₂ and brine to investigate the effect of surface tension on gas/liquid-relative permeability at varying temperatures, and agreed with researchers who also observed an increase in surface tension with the temperature elevation. They interestingly expressed that with an increase in surface tension, the relative permeability curve became steeper, and as the surface tension decreased, the relative permeability curves moved towards linearity (see Figure 3).

Wan et al. [52] studied the gas and liquid-relative permeability in carbonate (dolomite) reservoirs, at varying test conditions where the test temperature raised from an ambient value to 80 °C. They used different dolomite cores in the porosity range of 0.83–6.74% and permeabilities within 0.0005–0.2610 mD, and nitrogen as the gas phase along with the brine as the liquid phase. An increase in the temperature lowered the surface tension between gas and brine from 71.25 to 50.12 mN/m and affected the gas/liquid-relative permeability curve, as well.

Figure 3. Effect of surface tension on gas/liquid-relative permeability [37].

The possible reason for the variation in surface tension with pressure and temperature was associated with the thermodynamic properties of the fluid phase employed in the reported studies [53]. The majority of the reported studies used CO₂ as a gas phase which was soluble in water or brine at high pressures (surface tension decreases), but the solubility of CO₂ decreased with an increase in temperature (i.e., surface tension increased). It is to be emphasized that the variation in surface tension with pressure is attributed to the solubility/miscibility of the gas phase in the liquid phase, which is better justified by Henry's law. Accordingly, the solubility of a gas in a liquid is directly proportional to the pressure of that gas above the surface of the solution. Thus, all the gases used in the reported studies [15,37,38,48,50–52] had shown a decrease in surface tension with the increased pressure. The reason for these observations could be that the gas molecules were forced into the liquid under high-pressure conditions which caused the nature of liquid being closer to the gas phase, i.e., the liquid phase became lighter with a lower density. Thus, there was no effect on the surface tension under varying pressures till 3.45 MPa [49,50] at the ambient temperature. This observation is a reasonable one given that critical point of CO₂ is about 7.4 MPa and 32 °C [15,37,38,42–45,48–52]. In other words, as temperature is increased and pressure remains higher than the critical pressure of the gas, it may increase the surface tension between gas and liquid. However, few researchers [17,54] have mentioned that surface tension decreases with an increase in temperature in the gas/oil system below the critical pressure of the gas. The effect of temperature on surface tension was also related to the miscibility or solubility of the gas phase in the liquid. The solubility of a gas in the liquid phase is associated with the change in kinetic energy of the molecules [55]. Thus, through an increase in temperature, the kinetic energy of gas molecules also increases which can cause higher motion for gas molecules and finally assist the gas to escape from the liquid phase. Hence, this was a possible reason for the increase in surface tension with an increase in temperature as reported in the study of [38,48,50,51]. However, during the injection of steam and other gases for thermal recovery processes, where the pressure is maintained below 6.9 MPa, the surface tension between the gaseous and liquid phase decreases with an increase in temperature [40–42]. The reason for this observation is still debatable and not fully understood.

The aforementioned experimental studies show that gas/liquid-relative permeability is affected significantly by surface tension, and a linear relationship between the relative permeability and

saturation is observed at very low values of surface tension [15,48]. When the surface tension becomes lower than a threshold value, the impact of surface tension on the relative permeability becomes more pronounced [15,48]. Studies on the effect of surface tension on gas/liquid-relative permeability extracted from published literature are summarized in Table 2.

Table 2. Summary of the effect of surface tension (ST) on liquid/gas-relative permeability reported in reviewed studies.

Authors	Year	Porous Media–Fluid System	Temperature and Pressure	Effect of Pressure and Temperature on ST	Effect of ST on Relative Permeability
Longeron [15]	1980	Fontainebleau sandstone core–methane and heptane	71.1 °C (constant) 2.76–24.13 MPa	ST reduced with an increase in pressure at a constant temperature.	Both liquid and gas-relative permeability increased linearly with a decrease in ST.
Asar and Handy [48]	1988	Consolidated Berea sandstone core–methane and propane	21 °C (constant) 7.58–9.55 MPa	Reduction in ST from 0.03 to 0.82 mN/m with an increase in pressure at a constant temperature.	Oil-relative permeability decreased more rapidly comparing to gas-relative permeability with an increase in ST
Yang et al. [50]	2005	N/R-CO ₂ /Brine and Crude Oil	27–58 °C 0.12–13 MPa	Below 8.50 MPa, the ST decreased with an increase in temperature and vice versa were observed when pressure was above the 8.50 MPa. At specified temperature, with an increase in pressure, the ST decreased. At lower pressure, the ST decreased with an increase in temperature.	N/R
Chalbaud et al. [51]	2006	N/R-CO ₂ /brine	27–100 °C 0.12–13 MPa	ST decreased with an increase in pressure at a constant temperature but at lower pressure, the ST reduced with increase in temperature and vice versa at high pressure.	N/R
Bachu and Bennion [37]	2008	Sandstone core–CO ₂ /brine	41–125 °C 1–27 MPa	ST reduced with increase in temperature, but no effect of pressure has been reported.	Relative permeability to gas and brine both increased with decrease in ST.
Honarvar et al. [49]	2017	Iranian carbonate core–CO ₂ /brine	40–100 °C 13.79 MPa	Increase in temperature decreased the ST from 71.25 to 50.12.	N/R
Wan et al. [52]	2019	Carobonate (dolomite) core–nitrogen/brine	Ambient–80 °C		Changes the relative permeability curves for both the liquid and gas.

5.2. Viscosity Ratio

As mentioned earlier, the viscosity ratio is much more sensitive to temperature in heavy oil systems [19]. The viscosity ratio (defined as the ratio of the viscosity of the displaced phase to the viscosity of the displacing phase) reduces dramatically with increasing temperature, which may affect the relative permeability. Theoretically, the relative permeability to each phase depends on the distribution of the two phases within the pore space of the medium. As mentioned earlier, the capillary force is much stronger than other forces, and hence, it controls the fluid distribution [54]. It makes the relative permeability a function of only the phase saturation, as long as the capillary forces remain dominant force inside the porous medium. The results of Leverett [56] and Leverett and Lewis [57] support this concept. They conducted experiments in oil/water [56] and gas/oil [57] systems using a clean high permeable (3.2 to 6.2 Darcy) unconsolidated sand-pack with varying viscosity ratios (0.057 to 90.0) to understand the effect of viscosity ratio on relative permeability. They reported that the viscosity ratio had practically no effect on relative permeability. The relative permeability was a function of only the saturation. Apparently, the capillary force controlled the fluid distribution and the system remained strongly water-wet with all fluid pairs in their study. The study performed by Esmaeili et al. [39] on clean heavy viscous oil/water systems also confirmed this fact that relative permeability was not a function of viscosity ratio.

Yuster [58] suggested that relative permeability was not only a function of saturation, but also relied on viscosity ratio of the fluids. He concluded that an increase in viscosity ratio was the reason for the remarkable influence in relative permeability. However, Wyckoff and Bostet [59] did not make the similar observation as Yuster [58] did. In their experiment, the moderate variations in viscosity of

the fluid phases in an unconsolidated sand pack with permeability ranging from 3.2 to 6.0 Darcy failed to produce any change in the gas and oil-relative permeability values. They conducted the experiment using mixture of water (as a liquid phase) and sugar to attain the varying viscosity (0.9 to 3.4 cP) and carbon dioxide as a gaseous phase. However, their observed relative permeability curves were shifted from what they had obtain from water and gas system, but they ignored it because they were apparently close enough. Therefore, they [59] mentioned that gas/liquid-relative permeability was insensitive to the viscosity variation which was in contrast to Yuster [58]. Similarly, Craig [60] reported that the gas–oil-relative permeability ratio of Nellie Bly sandstone sample with 824 mD permeability and 28.1% porosity which showed no evidence for the variation with change in the oil viscosities in the range of 1.4 to 125 cP. Moreover, Sandberg [61] subsequently also reported that relative permeability was not affected by the variation in viscosity ratio and it was only a function of saturation. They used water as the wetting phase and different oils with varying viscosity as the oil phase. Figure 4 shows the slight variation in relative permeability curve reported by Sandberg [61], especially for the oil phase with changes in viscosity ratio, but they considered such differences to be within the acceptable error bands of the measurements. Additionally, it can be observed in Figure 4 that water-relative permeability displayed much smaller variations with viscosity ratio than the oil-relative permeability.

Figure 4. Effect of viscosity ratio on water/oil two-phase relative permeability versus water saturation [61].

A controversy remains regarding whether the viscosity ratio affects relative permeability or not [56–58,61]. Odeh [62] developed a theoretical expression to support Yuster’s [58] hypothesis about the dependency of relative permeability on the viscosity ratio in addition to the saturation. He measured two-phase relative permeability using different oils of varying viscosities. Fluid saturation was detected using the electrical resistivity technique. His theoretical [62] analysis agreed with Yuster’s [58] hypothesis. However, he also observed experimentally that relative permeability to oil, i.e., the non-wetting phase, was a function of saturation and viscosity ratio [62] but the water (wetting phase)-relative permeability was a function of water saturation alone. In addition, it was suggested by Odeh [62] that relative permeability curves of varying oil viscosities approached each other as the oil saturation decreased. Additionally, he [62] concluded that the effect of viscosity ratio on oil relative permeability decreased as the pore radius for oil flow (or the absolute permeability) increased. Therefore, the effect of viscosity ratio on the relative permeability of the non-wetting phase is maximum at the highest oil saturation. However, Baker [63] and Downie and Crane [64] criticized the Odeh [62] hypothesis that viscosity ratio may affect the relative permeability. The hypothesis of

Odeh [62], that the effect of viscosity ratio on relative permeability depends on the pore radius (absolute or intrinsic permeability), was supported by Velásquez [65]. The results suggest that the viscosity of the fluid would not affect the relative permeability if the size of the pore is large enough [65]. Downie and Crane [64] offered a different explanation for his observations [62] of the enhancement of oil-relative permeability at low water saturations and suggested that the variation in relative permeability was observed due to the compression and dehydration of the clay content present inside the core, which led to an enlargement of the flow channels. Donaldson et al. [66] suggested that the relative permeability dependency on viscosity ratio was associated with the wettability of the rock. They mentioned that if the viscosity of oil remains similar, relative permeabilities may change due to wettability alteration. However, if the viscosity of oils was not the same, the relative permeability may change with both the wettability and viscosity ratio [66].

Many researchers [46,67,68] have suggested a threshold value of the capillary number, up to which the viscous forces remain negligible compared capillary forces. For the flow passing through pores in the oil reservoirs, N_C (capillary number) typically is $\sim 10^{-6}$, which makes the flow capillary dominated [7]. Similar results were presented by other researchers [19,64,69] in describing the effect of viscosity ratio on relative permeability. Table 3 is a tabulation of some studies on the rock and fluid properties to assess the effect of viscosity ratio on relative permeability.

Table 3. Rock and fluid properties used in reported studies of the effect of viscosity ratio on relative permeability.

Authors	Year	Viscosity Ratio Range (cP)	Intrinsic Permeability Range (Darcy)
Leverett [56]	1939	0.057–90.0	3.2–6.8
Leverett and Lewis [57]	1941	1.86–20.2	5.4–16.2
Yuster [58]	1951	1–10	N/R
Wyckoff and Botset [59]	1936	9–29	0.45–0.49
Craig [60]	1971	1.4–125	0.80–0.82
Sandberg et al. [61]	1958	0.48–2.02	0.413–0.757
Odeh [62]	1959	0.44–82.7	0.0021–0.405
Baker [63]	1960	N/R	N/R
Downie and Crane [64]	1961	9.29–51.54	0.13–0.16
Velásquez [65]	2009	0.4–75.4	0.041–0.521
Donaldson, et al. [66]	1969	35–78	0.76–1.20
Gao et al. [67]	2013	N/R	N/R
Berry et al. [14]	1992	41.53–170.5	0.79–0.11
Muqem [17]	1996	215.35–22500	3.29–3.44
Modaresghazani [16]	2015	16.90–50.88	10.03–10.95

Peters and Flock [70] have explained how the viscosity ratio affects the residual fluid saturation. They mentioned that an unfavorable mobility ratio can generate viscous fingering, which would eventually affect the measured residual fluid saturation and relative permeability [70]. Nevertheless, it is well understood that fractional flow is the function of viscosity ratio which is highly sensitive to the temperature. Therefore, the temperature may indirectly affect the displacement efficiency and complicate the interpretation of relative permeability from fluid–fluid displacement tests, also known as unsteady-state tests. The complications generally originate due to the development of unstable displacement or viscous fingering.

Berry et al. [14] employed the unsteady-state techniques to measure two-phase gas/oil-relative permeability and measurement were made using the Johnson–Bossler–Neumann (JBN) [71] method. Nitrogen gas was the displacing phase and crude oil was the displaced phase [14]. They reported that with an increase in temperature, the viscosity ratio (ratio of oil viscosity to gas viscosity) decreased, which affected the gas/oil-relative permeability. Their reported results of the effect of temperature on oil/gas-relative permeability are shown in Figure 5. Muqem [17] also conducted a few experiments to understand the effect of varying viscosity ratios on two-phase gas/oil-relative permeability at different temperatures (75 and 120 °C). He conducted experiments on a sand pack with a porosity and permeability of 37.8% and 3.37 Darcy, respectively. The viscous refined oil as an oil phase and

nitrogen as a gaseous phase were used in his work. He opted for an unsteady-state method to interpret the two-phase gas/liquid-relative permeability in the presence of irreducible water saturation. The observation from his experiments strongly suggested that relative permeabilities to both gas and oil were influenced by the temperature. The endpoint-relative permeability to oil was decreased from 0.76 to 0.68 and endpoint-relative permeability for gas was increased from 0.61 to 0.72. On the other side, the irreducible water saturation was observed to be increased with temperature. The probable reason justified by Muqem [17] for observing the influence in gas/oil-relative permeability was due to the change in viscosity ratio with an increase in temperature.

Figure 5. Effect of viscosity ratio on two-phase gas/liquid-relative permeability with varying temperature [14,16].

Modaresghazani [16] studied the effect of varying temperature on gas/water steady-state- and unsteady-state-relative permeability using water as the displaced phase and nitrogen gas as the displacing phase. The viscosity ratio decreased with increasing temperature. The variation in viscosity ratio from ambient temperature to 40 °C did not affect relative permeability, but the relative permeability shape changed at 80 °C. The result demonstrated the alteration of the gas-relative permeability curve with temperature; however, the change was small and it can be argued that the variation in gas-relative permeability was within the experimental error [16].

Gao et al. [67] reported that due to the decrease in viscosity of heavy oil at high-temperature conditions, the residual oil saturation declines. Esmaeili et al. [19] also reported the effect of viscosity ratio on two-phase oil/water-relative permeability in heavy oil systems showing that the viscosity variation of fluid may affect the relative permeability. The reason for this change was attributed to the negation of capillary-dominated fluid distribution in porous media. They mentioned that if any parameter nullifies the capillary control, then the fluid distribution in the porous medium could be governed by other forces rather than only capillary forces.

Most of the opinions of researchers [14,16,17,58,62,70] on the effect of viscosity ratio on two-phase gas/liquid-relative permeability stem from the displacement tests which were subject to viscous fingering. However, if the fundamental assumption, i.e., the fluid distribution in porous media is a capillary force-dominated phenomenon, the relative permeabilities should not change with the change in viscosity of a fluid (gas and oil), and hence, with the viscosity ratio. Moreover, the results presented by several authors [14,16,17,70] on the effect of temperature on two-phase gas/liquid-relative permeabilities due to change in viscosity ratio affirm that the fundamental assumption (i.e., capillary forces are controlling factor for fluid distribution) may not be a valid one. Several other researchers [56,57,59,61,62], however, are not in agreement with this view. They argue that the viscosity ratio may affect relative permeabilities based on their studies with of low- to moderate-viscosity oils. Fundamentally though,

one must recognize that the displacement tests associated measurement of relative permeabilities are subjected to some degree of viscous fingering, which may contribute towards inaccurate or complicated interpretations of the effects of viscosity ratio on relative permeabilities. Therefore, relative permeabilities by some authors, [14,16,17] as reported from their displacement tests using oil of high viscosity, confirm that surface forces were not the controlling force for the fluid distribution in porous media; rather, the temperature was, as the viscosity changes were occurring as the temperature was increasing. This understandably makes the viscosities of fluids (or viscosity ratio) a key influencing and functional parameter affecting relative permeabilities, in addition to fluid saturations.

5.3. Wettability

Wettability is a deterministic property of a porous medium and is defined as the relative tendency of one fluid to adhere to the solid surface in the presence of another immiscible fluid [11]. The surface or interfacial energy of different interfaces determine the wettability. For a gas/oil system, the rock is fundamentally oil-wet when the surface energy of rock/oil interface is lower than that of the rock/gas interface, which is generally valid for the reservoir systems [72]. The non-wetting phase (gas) tends to occupy larger pores and the wetting phase (oil) tends to flow in smaller pores. The opposite can be true for a gas-wet system, where oil (non-wetting phase) flows in larger pores and gas (wetting phase) moves in smaller pores.

Moore and Slobod [73] stated that wettability is the most important parameter in the immiscible displacement process which has a significant effect on two-phase-relative permeability [73]. Wagner and Leach [74] have further investigated the enhancement in oil displacement efficiency with wettability alteration. Froning and Leach [75] have also illustrated the improvement in oil recovery from field tests in Clearfork and Gallup reservoirs by wettability alteration. Penny et al. [76] have discussed a technique to enhance the well stimulation by altering the wettability for gas/water systems. In their experiment, they added a surfactant in the fracturing fluid [76]. Penny et al. [76] also believed that the increase in production was achieved due to wettability alteration. However, they were not able to demonstrate the wettability alteration [76]. Conway et al. [77] extended the work carried out by Penny et al. [76] and investigated the effect of surface tension reducing agent on two-phase gas/brine-relative permeability. The study was conducted on both the Ohio sandstone and Blue Greek coal and they observed no effect on gas-relative permeability due to the reduction in surface tension [77].

Al-Siyabi et al. [78] measured the gas/oil contact angle of four binary mixtures including $C_{1/n}$ - C_4 , $C_{1/n}$ - C_8 , $C_{1/n}$ - C_{10} , and $C_{1/n}$ - C_{14} at reservoir conditions. They found that gas/oil contact angles were about 20° for surface tension values greater than 0.2 mN/m [78]. Morrow and McCaffery [79] reported a summary of gas/liquid displacement behavior in a low-energy porous polytetrafluoroethylene (Teflon) core. The contact angle of water against air on smooth Teflon was 108° . In addition, Morrow and McCaffery [79] also studied the effect of wettability on relative permeability in artificial PTFE (Polytetrafluoroethylene) cores for different wetting situations achieved by utilizing different fluids and extent of roughness. They concluded that the liquid saturation decreased with an increase in contact angle from 22 to 108° which enhanced the gas-relative permeability. Moreover, an increase in the contact angle to higher than 90° makes the medium neutrally-wet or gas-wet. Zisman [80] reviewed the relationship between the contact angle to liquid and solid constitution on low- and high-energy surfaces, both bare and covered with a condensed monomolecular adsorbed film. Zisman reported that even a single, close-packed, adsorbed monolayer of the wetting agent was sufficient to convert the wetting properties of a high-energy surface into those of a low-energy surface. This demonstrated the possibility of varying the wettability of a high-energy rock surface from preferential liquid-wetting to gas-wetting by adsorption of a monolayer of an organic polar compound [80]. However, wettability alteration to preferential gas-wetting in reservoir rocks were not documented in the petroleum literature [22,81].

Li and Firoozabadi [82] have investigated the effect of wettability alteration on gas/liquid-relative permeability using capillary tubes and consolidated sandstones. The wettability was altered with

the help of chemicals. They found that liquid rise in the capillary tube decreased (sometimes to the negative values) and the contact angle increased from 0 to 60° for oil/gas and 0 to 118° for water/gas system when the chemical concentration was increased to 1 wt% [82]. In a sandstone core, they found that gas-relative permeability (k_{rg}) at the residual oil saturation of 16.2% increased from 0.54 to 0.89. The endpoint-relative permeability to oil (k_{ro}^0) also increased with the chemical treatment. Thus, both the oil and gas-relative permeability can be enhanced by wettability alteration. Jiang [72] have proposed that if the surface energy is low for rock/water and rock/oil in gas/liquid/rock systems, where water is present as the irreducible water saturation, the rock may become intermediate gas-wet. Habowski [83] reported that a shift in relative permeability and an increase in irreducible water saturation occurred due to an increase in temperature. He further specified that adhesion tension decreases with an increase in temperature which affects the relative permeability and reduces the relative permeability ratio [83].

Many researchers have reported contrary opinions to the aforementioned results. For instance, Wang and Gupta [84] reported that an increase in temperature caused the quartz surface to become more oil-wet. Karyampudi [85] also supported Wang and Gupta's findings. Blevins et al. [86] in their case study mentioned that sandstone reservoir became oil-wet during steam injection. Escrochi et al. [87] have also published an interesting result that the rock surface tended toward more oil-wet from water-wet with an increase in temperature and later reverted to the initial wetting state (more water-wet by a further increase in temperature). A summary of the results from our review of the literature on effects of wettability alteration on two-phase gas/liquid-relative permeabilities with increasing temperature is presented in Table 4.

Table 4. Studies on effects of wettability on relative permeabilities.

Authors	Year	Porous Media-Fluid System	Contact Angle	Pressure and Temperature	Effect of Wettability on Relative Permeability
Moore and Slobod [73]	1956	Core-oil/gas	N/R	N/R	Both the relative permeability curves of gas and oil has been affected
Wagner and Leach [74]	1959	Quartz-Soltrol C/gas	30 to 130°	3.45 MPa and 35 to 57.2 °C	N/R
Zisman [80]	1964	Silica surface-hexadecane/gas	N/R	N/R	N/R
Habowski [83]	1966	Sandstone-oil/gas	N/R	N/R	Change in relative permeability curves for both the phases have been observed.
Froning and Leach [75]	1967	Sandstone-crude oil/gas	N/R	N/R	N/R
Morrow and McCaffery [79]	1978	Artificial PTFE (teflon)-n-Alkanes and air	22 to 108°	N/R	Gas-relative permeability increased with increase as system becomes neutrally-wet or gas-wet.
Penny et al. [76]	1983	Ottawa sand-oil/gas	N/R	62 MPa and 82.2 °C	Relative permeability to oil enhanced
Blevins et al. [86]	1984	Carbonate (dolomite) core-nitrogen/brine	N/R	Ambient-80 °C	Changes the relative permeability curves for both the liquid and gas.
Conway et al. [77]	1995	Blue Creek coal-brine/methane gas	N/R	N/R	Brine-relative permeability enhanced but not effect on gas-relative permeability has been observed.
Wang and Gupta [84]	1995	Quartz crystal-crude oil/gas	22 to 135°	20.68 MPa and 65 to 135 °C	N/R
Karyampudi [85]	1995	Sandstone-crude oil/gas	32 to 172°	4.4 MPa and 24 to 196 °C	Oil-relative permeability declined sharply
Al-Siyabi et al. [78]	1997	Teflon	N/R	N/R	N/R
Li and Firoozabadi [82]	2000	Consolidated sandstone core and capillary tube-water/gas and oil/gas	0 to 118° for water/gas and 0 to 60° for oil/gas	N/R	Both the oil- and gas-relative permeability enhanced with the increase in contact angle and wettability alteration.
Escrochi et al. [87]	2008	Viscous crude oil/gas	20 to 126°	NR and 23 to 93 °C	N/R
Jiang [72]	2018	Water/gas	11 to 89°	N/R	N/R

6. Effect of Temperature on Gas/Oil-Relative Permeability Curves

6.1. Irreducible Water Saturation

A few studies [88–90] have suggested the dependency of irreducible water saturation on the pressure gradient developed in the porous medium during the oil injection. When similar flow rates are used in oil injections at different temperatures, the pressure gradient becomes lower at higher temperatures, especially in viscous oil systems, which increases the irreducible water saturation. Craig [60] postulated that irreducible water saturation can also be related to the wettability of the formation rock. Narahara et al. [91] conducted a study to understand the effect of irreducible water saturation on gas/liquid-relative permeability. Berea sandstone cores were used with refined white oil (20 cP at room temperature), which was displaced by air in the absence and presence of S_{iw} . The two different measurement techniques (gas flooding and centrifuge technique) were utilized for relative permeability measurements. The results showed a good match between the gas/liquid-relative permeability data with both techniques in the absence of irreducible water saturation. Later, four gas floods were performed at four different initial water saturations in the gas/oil system. Figure 6 depicts the gas/liquid-relative permeability calculated from these gas flooding tests. In this figure, the initial water is used as the reference fluid, and relative permeability is plotted as a function of the total liquid (oil plus water) saturation. The oil-relative permeability data varied considerably at different initial water saturations, especially when the initial water saturation exceeded 18.5%. As seen in Figure 6, the gas-relative permeability curves, at all values of the irreducible water saturation, are essentially identical which implies that gas-relative permeability is only a function of gas saturation. This can be rationalized as follows. The gas phase occupies the largest available pores in a water-wet system containing gas, oil, and water. The effective permeability to gas is governed by the ability of gas to flow through relatively few of the largest pores, while the oil flow occurs in both large pores and especially small pores where the presence of water phase acts as a barrier for the oil flow. This is not the case for the oil phase, as it shares the remaining pore space with water. At zero initial water saturation, all of the remaining pore space is open for the oil flow, which results in the highest relative permeability for oil at any given liquid saturation. As the initial water saturation increases, the fraction of available pore space to oil decreases. Consequently, the oil-relative permeability diminishes.

Figure 6. Effect of irreducible water saturation on two-phase gas/oil-relative permeability [91].

Corey [92] simplified the analytical expression given by Kozeny–Carman for relating the gas/liquid-relative permeability to fluid saturation. Later, McNiel and Moss [93] extended the work carried out by Corey [92] and concluded that relative permeability was a function of temperature. The reason given was that the residual oil saturation may decrease with an increase in temperature. Naar

and Henderson's [94] imbibition model suggests the possibility that the irreducible water saturation might be a function of temperature as well. Davidson [95] investigated the effect of temperature on relative permeability for both oil/water and gas/water systems. He reported that an increase in irreducible water saturation occurred with an increase in temperature for oil/water systems. However, there was no temperature impact on irreducible water saturation in gas/water systems. A similar observation has been reported by Lo et al. [96]. Table 5 lists the studies on the effect of irreducible water saturation on two-phase gas/oil-relative permeabilities.

Table 5. Effect of irreducible water saturation on two-phase gas/oil-relative permeabilities.

Authors	Year	Irreducible Water Saturation (Swir) Range (%)	Effect of Swir on Relative Permeability
Narahara et al. [91]	1993	0–26.5	Oil-relative permeability changed and no effect on gas-relative permeability has been observed
Corey [92]	1954	N/R	Liquid-relative permeability has been affected
Moss and McNiel [93]	1959	0–13	Relative permeability curves to both the phases gas and oil has been changed
Naar and Henderson's [94]	1961	6–18	N/R
Davidson [95]	1969	4–4.12	N/R
Lo et al. [96]	1973	5–523	N/R
Berry et al. [14]	1983	0.20–0.25	Relative permeability curve for both the phase gas and oil has been changed.

Berry et al. [14] performed few experiments for gas/liquid-relative permeability and found that as the temperature elevated, the irreducible water saturation increased, as can be seen in Figure 7. They used different techniques to establish irreducible water saturation in their experiments, i.e., centrifuge drainage at 93 °C and oil flooding at ambient condition, but did not explain the reason for the increase in irreducible water saturation with the temperature rise. However, a plausible reason for such increase in S_{iw} was a reduction in the oil viscosity at high temperature. At 25 °C, the viscosity of oil was high and thus the oil was able to sweep the water to larger extent. However, the viscosity of oil decreased significantly at higher temperature which affected the sweep efficiency of oil and higher magnitude of irreducible water saturation was observed.

Figure 7. Effect of temperature on irreducible water saturation, reported by Lo et al. [96] and Berry et al. [14].

Esmaili et al. [19] stated that irreducible water saturation depends on three parameters: wettability, pore geometry, and capillary number, all of which may change with temperature. Wettability may change due to the presence of chemical species like clay or asphaltene. Moreover, in clay-rich formations, it was observed that in-situ stresses might increase due to temperature, which may result in swelling and this might change the pore geometry of the formation [97,98]. However, the variation in such parameters (wettability and pore geometry) with temperature are not theoretically expected due to the absence of reactive minerals and adsorbed polar chemicals. Thus, the only remaining parameters that could be the reason for the change in irreducible water saturation with temperature is the variation in the capillary number.

6.2. Residual Oil Saturation

Among many studies on the effect of temperature on the two-phase flow that were published during the past sixty years, a large majority reported that the residual oil saturation decreased as temperature increased [19], at least for the oil/water system. Nonetheless, several studies reported no change in residual oil saturation with temperature [19]. The following discussions provide some insight into the current understanding of the effect of temperature on S_{or} in the gas/liquid system.

Longeron [15] reported that with an increase in temperature, the surface tension (ST) decreases, which causes a reduction of residual oil saturation in gas/oil systems. Later, Asar and Handy [48] verified these results and agreed with Longeron [15], that the amount of oil remained in the system after gas flooding depended on the surface tension. Cai et al. [38] also found that an increase in temperature lowered the surface tension and residual oil saturation. Yang et al. [50] conducted an experiment with CO₂ gas and crude oil system and reported that residual oil saturation decreased with an increase in temperature from 27 to 58 °C at a constant pressure of 8.879 MPa. In addition, they reported that the decrease in residual oil saturation was achieved by the reduction of surface tension due to the increase in temperature [50]. Chalbaud et al. [51] have supported this hypothesis by extending the same test to 100 °C and observed similar results as Yang et al. [50]. Bachu and Bennion [37] have asserted that two-phase gas/liquid-relative permeability was a function of saturation, as well as of surface tension and wettability. However, they did not present any data on change of residual oil saturation with temperature [37]. Honarvar et al. [49] agreed with the idea that both surface tension and residual oil saturation decreased with increasing temperature. Berry et al. [14] recognized the role of viscosity ratio in decreasing the residual oil saturation with increasing temperature in gas/oil systems. They observed a significant decrease in residual oil saturation at a higher temperature, as depicted in Figure 8.

Figure 8. Effect of temperature on residual oil saturation in the gas/oil system.

Davidson [95] evaluated the effect of temperature on nitrogen/mineral oil-relative permeability ratio in the absence of irreducible water saturation and observed that the residual oil saturation decreased at higher temperatures (see Figure 8); however, the reduction is fairly lower than that of Berry's study [14]. Davidson concluded the temperature-dependency of relative permeability in gas/oil systems was due to the slippage effect. It should be highlighted that the dependency of relative permeability on temperature was not because of the solubility of the gas in white oil, as it decreased with an increase in temperature [95]. Akhlaghinia et al. [13] performed several experiments to assess the effect of temperature on residual saturation during the measurement of gas/oil-relative permeability. They used CH₄/CO₂ to push heavy oil out of the system and reported that residual oil saturation decreased with an increase in temperature (28–52 °C), as shown in Figure 8.

Due to the small number of reported studies on the effect of temperature on gas/oil-relative permeability, it is difficult to make a firm statement the factor that is dominant causing a reduction of residual oil saturation with increasing temperature in gas/oil systems. However, the comprehensive literature review carried out by Esmaeili et al. [19] for oil/water systems reveals that the decrease in residual oil saturation is related to the reduction in oil viscosity, changes in wettability and surface tension and other possible factors. It is likely that the same reasons can be considered also for the gas/oil systems, but their relative importance could be different.

6.3. Critical Gas Saturation

The critical gas saturation can be measured in two ways, either by solution gas drive tests or by external gas drive tests. The critical gas saturation is often determined from the gas-relative permeability curve extracted from an external gas drive test. The literature strongly suggests that the critical gas saturation for solution gas drive may be different from the value measured by external gas drive tests [34]. In fact, the entire relative permeability curve is likely to be different for solution gas drive. Foamy oil flow, however, is not expected to play a significant role in the external gas drive process but may be an important consideration in the solution gas drive. Recently, Wan et al. [52] have measured brine/nitrogen-relative permeability at varying temperatures. They first injected at least 5 PV of brine through core samples and then injected nitrogen gas as a displacing phase. The observed critical gas saturation was in the range of 0.06–0.22. However, it is not clear how the critical gas saturation was determined in their study. Data reported in the literature on critical residual oil saturation that show a variation with temperature are very limited

7. Summary of Discussions

As evident from the preceding discussions, the techniques for the measurement of relative permeability may significantly suffer from experimental artifacts, depending on the type of utilized technique. Therefore, it is important to first understand the issues and come out with possible solutions for minimizing experimental errors; for example, the viscous fingering of the gas flow due to the instability of gas flooding, the gas-override problems because of the density difference, the reliable fluid saturation determination, and the capillary end effects corresponding to the low-pressure gradient of low viscous fluid are the clear samples of experimental challenges during gas/liquid-relative permeability which should be paid attention prior to any measurement.

The capillary end effect leads to the accumulation of a wetting phase at the production outlet of the core or porous medium, and also results in the development of abnormal pressure gradient and saturation gradient at the outlet which makes the interpretation of relative permeability so complex. Therefore, it is advisable not to obtain the pressure data directly from the end of the outlet of the porous medium, but rather by positioning the pressure sensor point a few centimeters away from both ends. This will enable us to neglect or significantly diminish the concerns related to the capillary end effects. Additionally, one can record the segmental pressure-drop along various sections of the porous medium in the coreholder, and then its summation can be matched to the actual recorded overall pressure drop inside the system (obtained away from the end) to ensure the negation of end effects

during relative permeability measurements. This approach can also aid in obtaining an additional insight on the flow behavior during the test in a particular segment in the core, and can be used in the interpretation of displacement data.

As far as the errors with phase saturation measurement are concerned, one needs to use the material balance check to measure the phase saturation initially, instead relying on any analytical tools for measuring saturation which have their own artifacts. Measuring fluid saturation based on the material balance method may truly aid in obtaining reliable data for the meaningful interpretation of two-phase gas/oil-relative permeability.

The additional issues with steady- and unsteady-state techniques persist, i.e., the time-consuming nature of the steady-state method and displacement instability in unsteady-state measurement techniques. The important concern related to displacement instability in the unsteady-state method hinders the maintenance of the capillary controlled fluid distribution in the reservoir and this leads to the wrong interpretation of relative permeability behavior. The displacement instability increases when we displace a heavy viscous oil (heavy oil) with a lighter phase. Thus, the result presented by a few researchers [13–17,50] were controversial as they conducted the experiments at different temperatures which affected their fluid viscosity. This change in fluid viscosity affected the displacement stability in their studies. Such instabilities occur due to a viscosity difference between the displaced and displacing phase, also known as viscous fingering (raised due to the unfavorable mobility ratio) and are yet another reason for the variation in the relative permeability curves. However, the unstable displacement may be eliminated by reducing the flow rate which can help in attaining the desired stability number proposed by Peters and Flock [70] to achieve the stable oil displacement in the system. It should be mentioned that the gas flooding, especially for heavy oil systems, inherently creates an unstable condition. Nevertheless, we can take the benefit of the density difference between gas and liquid phase to stabilize the gas flow by gravity. According to the literature, no researcher has considered such solutions to eliminate the displacement instability issues while measuring relative permeability for the gas/oil system. Therefore, the results presented by different researchers were contradictory.

In addition to the effect of temperature on viscosity or fluid phase and the gas/oil two-phase-relative permeability, one also needs to account for the effect of temperature on other fluid/fluid, rock/fluid interaction parameters and rock properties including wettability, surface tension and pore structure of the system which can indirectly affect the gas/oil-relative permeability. Several researchers [73,74,76,77,82,85,86] have reported that wettability changes with the temperature change. Thus, it will be unreliable to interpret the two-phase gas/oil-relative permeability of the system where the wettability of system alters with temperature. The determination of wettability alteration potential in a particular system depends on the various parameters (i.e., mineralogical and chemical composition of the rock and fluid present in the reservoir system). The change in wettability may surely affect the fluid distribution in the entire reservoir system and undoubtedly influence the relative permeability. Hence, wettability becomes another functioning parameter for relative permeability. Thereby, it is prudent to analyze the wettability of different rock/fluid system at elevated temperature rather than to generalize the effect of wettability on two-phase gas/liquid-relative permeability.

The effect of surface tension on relative permeability is generally based on the capillary number for hydrocarbon recovery. As is evident from the capillary number definition, lowering the surface tension leads to an increase in the capillary number and thus, more oil can be mobilized out of through the pore network. The increase in recovery can be achieved by increasing the contact between the displacing and displaced fluid (i.e., eliminate the fluid bypassing), which enhances the production efficiency of the oil at the specific velocity and viscosity of the displacing fluids [15]. Generally, at high temperatures, especially in the gas/oil system, the surface tension affects the capillary number significantly [49,50]. The principle of the variation in ST in the gas/liquid system is based on the kinetic theory of gases and thermodynamic equilibrium properties of fluids present in the system. Different researchers [15,37,48–52] have given different opinions on the effect of temperature and pressure on surface tension, which indirectly affects the relative permeability. However, the surface tension

essentially depends on the fluid properties and test conditions, as discussed above. Therefore, it is not recommended to generalize the effect of temperature on surface tension, whose variation can affect the two-phase gas/oil-relative permeability, before understanding the properties and type of the fluids present in the reservoir system.

8. Conclusions

The emphatic answer to our leading question in title of this paper “*Can Effects of Temperature on Two-Phase Gas/Oil-Relative Permeabilities in Porous Media be Ignored?*” is *No, we cannot!* The preceding review of the effect of temperature on two-phase gas/oil-relative permeabilities shows that the underlying issues still remain unresolved. Due to the scarcity of the literature data available on the effect of temperature on two-phase gas/oil-relative permeability, plus the contradictions among them, it is premature to make firm and conclusive observations. However, our review identified four key issues that have contributed to the contradictions; notably, (1) the experimental techniques for measuring gas/oil-relative permeability suffers from experimental artifacts, (2) gas-slippage effect, (3) capillary end effect, and (4) complication in measuring phase saturation at varying test conditions.

The reliable interpretation of relative permeability measurements requires the capillary forces to control the fluid flow and distribution in the porous media. However, it is quite difficult to maintain it in the heavy oil reservoirs due to temperature sensitiveness to certain key parameters, such as wettability, surface tension and variations of fluid properties (such as viscosity and density) at elevated temperatures. Therefore, it can be said that relative permeabilities to fluids are indirectly affected by temperature due to changes in such properties and parameters.

Our analysis strongly suggests that there is room for improvement in both the experimental techniques and theoretical understanding of the effect of temperature on two-phase gas/oil-relative permeabilities, and it is very important and critical to do so, particularly for the heavy oil reservoirs where the thermal recovery processes are implemented. Without a reliable understanding of the relative permeability characteristics, the modeling of any thermal recovery process for heavy oil reservoirs will remain inadequate. The measurement should include not only the two-phase gas/oil-relative permeability tests, but also the measurements of fluid properties, rock/fluid and fluid/fluid interactions like viscosities (and densities) of different phases, wettability, surface tensions at different temperatures. The reason for such recommendation is that it will be impossible to generalize the effects of temperature on gas/liquid-relative permeabilities without considering those measurements. Unfortunately, the investigation of the effect of temperature on gas/oil-relative permeabilities, especially for the heavy oil systems, are fraught, with severe experimental difficulties and challenges in regard to reliable data gathering. This undeniably remains an area that needs a lot of research.

Author Contributions: Conceptualization, H.S. and B.M.; methodology, S.K. and S.E.; validation, S.K., S.E., H.S. and B.M.; formal analysis, S.K.; investigation, S.K.; resources, H.S. and B.M.; data curation, S.K.; writing—original draft preparation, S.K.; writing—review and editing, S.E., H.S. and B.M.; visualization, S.K.; supervision, H.S. and B.M.; project administration, H.S. and B.M.; funding acquisition, H.S. and B.M. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by Natural Sciences and Engineering Research Council of Canada: IRCPJ 505512–15.

Acknowledgments: 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.

Conflicts of Interest: The authors declare no conflict of interest.

Notations

Notations	Meanings
b	Slip factor
k	Absolute permeability to liquid
k_r	Relative Permeability
k_{rg}	Relative Permeability to Gas
k_{rl}	Relative Permeability to Liquid
k_{ro}^0	Endpoint Relative Permeability to Liquid
p_m	Mean pressure
S	Saturation
S_o	Oil Saturation
S_{or}	Residual Oil Saturation
γ	Mean free path of the gas
N/R	Not Reported
wt%	Weight percent
c	Proportionality factor
k_{ro}	Relative Permeability to Oil
k_g	Absolute permeability to gas
k_{rw}	Relative Permeability to Water
k_g^∞	intrinsic permeability to gas at an infinite pressure
N_C	Capillary number
r	Average size of the capillaries
S_w	Water Saturation
S_{gc}	Critical Gas Saturation
S_{lr}	Residual Liquid Saturation
ST	Surface Tension
HP/HT	High pressure/high temperature

References

1. Ghoojani, E.; Kharrat, R.; Vossoughi, M.; Bolouri, S.H. A review on thermal enhanced heavy oil recovery from fractured carbonate reservoirs. *J. Pet. Environ. Biotechnol.* **2011**, *2*. [\[CrossRef\]](#)
2. Jiang, Q.; Thornton, B.; Russel-Houston, J.; Spence, S. Review of thermal recovery technologies for the clearwater and lower grand rapids formations in the cold lake area in Alberta. *J. Can. Pet. Technol.* **2010**, *49*, 2–13. [\[CrossRef\]](#)
3. Irani, M.; Cokar, M. Understanding the Impact of Temperature-Dependent Thermal Conductivity on the Steam-Assisted Gravity-Drainage (SAGD) process. Part 1: Temperature front prediction. In Proceedings of the Heavy Oil Conference-Canada, Calgary, AB, Canada, 10–12 June 2014.
4. Ashrafi, M.; Souraki, Y.; Torsaeter, O. Investigating the temperature dependency of oil and water relative permeabilities for heavy oil systems. *Trans. Porous Med.* **2014**, *105*, 517–537. [\[CrossRef\]](#)
5. Hamouda, A.; Karoussi, O. Effect of temperature, wettability and relative permeability on oil recovery from oil-wet chalk. *Energies* **2008**, *1*, 19–34. [\[CrossRef\]](#)
6. Punase, A.; Zou, A.; Elputranto, R. How do thermal recovery methods affect wettability alteration? *J. Pet. Eng.* **2014**, *2014*. [\[CrossRef\]](#)
7. Kantzas, A.; Bryan, J.; Taheri, S. Fundamentals of fluid flow in porous media. Chapter 2: Pore size distribution. In *Engineering Fluid Mechanics*; Springer: Singapore, 2012; pp. 155–169.
8. Klinkenberg, L. *The Permeability of Porous Media to Liquids and Gases*; American Petroleum Institute: New York, NY, USA, 1941.
9. Letham, E.; Bustin, R. Klinkenberg gas slippage measurements as a means for shale pore structure characterization. *Geofluids* **2016**, *16*, 264–278. [\[CrossRef\]](#)
10. Wu, K.; Li, X.; Guo, C.; Wang, C.; Chen, Z. A unified model for gas transfer in nanopores of shale-gas reservoirs: Coupling pore diffusion and surface diffusion. *SPE J.* **2016**, *21*, 1583–1611. [\[CrossRef\]](#)
11. Anderson, W.G. Wettability literature survey-part 6: The effects of wettability on waterflooding. *J. Pet. Technol.* **1987**, *39*, 1605–1622. [\[CrossRef\]](#)

12. Buckley, S.E.; Leverett, M. Mechanism of fluid displacement in sands. *Trans. AIME* **1942**, *146*, 107–116. [\[CrossRef\]](#)
13. Akhlaghinia, M.; Torabi, F.; Chan, C.W. Experimental investigation of temperature effect on three-phase relative permeability isoperms in heavy oil systems. *Fuel* **2014**, *118*, 281–290. [\[CrossRef\]](#)
14. Berry, J.; Little, A.; Skinner, R. Differences in gas/oil and gas/water relative permeability. In Proceedings of the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, USA, 22–24 April 1992.
15. Longeron, D. Influence of very low interfacial tensions on relative permeability. *Soc. Pet. Eng. J.* **1980**, *20*, 391–401. [\[CrossRef\]](#)
16. Modaresghazani, J. Experimental and Simulation Study of Relative Permeabilities in Heavy Oil/Water/Gas Systems. Ph.D. Thesis, University of Calgary, Calgary, AB, Canada, March 2015.
17. Muqem, M.A. Effect of Temperature on Three-Phase Relative Permeability. Ph.D. Thesis, University of Alberta, Edmonton, AB, Canada, 1996.
18. McCaffery, F.G. The Effect of Wettability on Relative Permeability and Imbibition in Porous Media. Ph.D. Thesis, University of Calgary, Calgary, AB, Canada, 1973.
19. Esmaeili, S.; Sarma, H.; Harding, T.; Maini, B. Review of the effect of temperature on oil-water relative permeability in porous rocks of oil reservoirs. *Fuel* **2019**, *237*, 91–116. [\[CrossRef\]](#)
20. Egermann, P.; Vizika, O. Critical gas saturation and relative permeability during depressurization in the far field and the near-wellbore region. In Proceedings of the Annual Technical Conference and Exhibition, Dallas, TX, USA, 1–4 October 2000.
21. Maini, B.; Kokal, S.; Jha, K. Measurements and correlations of three-phase relative permeability at elevated temperatures and pressures. In Proceedings of the Annual Technical Conference and Exhibition, San Antonio, TX, USA, 8–11 October 1989.
22. Ahmed, T. Chapter 11: Oil recovery mechanisms and the material balance equation. In *Reservoir Engineering Handbook*, 3rd ed.; Gulf Professional Publishing: Huston, TX, USA, 2006.
23. Honarpour, M.M. *Relative Permeability of Petroleum Reservoirs*; CRC Press: Boca Raton, FL, USA, 2017.
24. Li, K.; Horne, R.N. Comparison of methods to calculate relative permeability from capillary pressure in consolidated water-wet porous media. *Water Resour. Res.* **2006**, *42*. [\[CrossRef\]](#)
25. Sarma, H.; Maini, B.; Jha, K. An unsteady-state technique for three-phase relative permeability measurements. *J. Can. Pet. Technol.* **1994**, *33*. [\[CrossRef\]](#)
26. Counsil, J.R. Steam-Water Relative Permeability. Ph.D. Thesis, Stanford University, Stanford, CA, USA, May 1979.
27. Estes, R.K.; Fulton, P.F. Gas slippage and permeability measurements. *J. Pet. Technol.* **1956**, *8*, 69–73. [\[CrossRef\]](#)
28. Fulton, P.F. The effect of gas slippage on relative permeability measurements. *Prod. Mon.* **1951**, *15*, 14–19.
29. Li, K.; Horne, R.N. Gas slippage in two-phase flow and the effect of temperature. In Proceedings of the Western Regional Meeting, Bakersfield, CA, USA, 26–30 March 2001.
30. Mahiya, G.F. *Experimental Measurement of Steam-Water Relative Permeability*; Stanford University: Stanford, CA, USA, 1999.
31. Sampath, K.; Keighin, C.W. Factors affecting gas slippage in tight sandstones of cretaceous age in the Uinta basin. *J. Pet. Technol.* **1982**, *34*, 2715–2720. [\[CrossRef\]](#)
32. Wei, K.; Morrow, N.; Brower, K. Effect of fluid, confining pressure, and temperature on absolute permeabilities of low-permeability sandstones. *SPE Form. Eval.* **1986**, *1*, 413–423. [\[CrossRef\]](#)
33. Rose, W.D. Permeability and gas-slippage phenomena. *API Drill. Prod. Pract.* **1948**, *234*, 127–135.
34. Maini, B. Is it futile to measure relative permeability for heavy oil reservoirs? *J. Can. Pet. Technol.* **1998**, *37*, 56–62. [\[CrossRef\]](#)
35. Kadeethum, T.; Sarma, H.; Maini, B. Overcome viscous fingering effect in heavy oil reservoirs by an optimized smart water injection scheme. In Proceedings of the Canada Heavy Oil Technical Conference, Calgary, AB, Canada, 15–16 February 2017.
36. Sarma, H. Viscous fingering: One of the main factors behind poor flood efficiencies in petroleum reservoirs. *Powder Technol.* **1986**, *48*, 39–49. [\[CrossRef\]](#)
37. Bachu, S.; Bennion, B. Effects of in-situ conditions on relative permeability characteristics of CO₂-brine systems. *Environ. Geol.* **2008**, *54*, 1707–1722. [\[CrossRef\]](#)

38. Cai, B.-Y.; Yang, J.-T.; Guo, T.-M. Interfacial tension of hydrocarbon + water/brine systems under high pressure. *J. Chem. Eng. Data* **1996**, *41*, 493–496. [[CrossRef](#)]
39. Esmaeili, S.; Sarma, H.; Harding, T.; Maini, B. The effect of temperature on two-phase oil/water relative permeability in different rock/fluid systems. In Proceedings of the Annual Technical Conference and Exhibition, Calgary, AB, Canada, 30 September–2 October 2019.
40. Maini, B.; Batycky, J. Effect of temperature on heavy-oil/water relative permeabilities in horizontally and vertically drilled core plugs. *J. Pet. Technol.* **1985**, *37*, 1500–1510. [[CrossRef](#)]
41. Polikar, M.; Ferracuti, F.; Decastro, V.; Puttagunta, R.; Ali, S. Effect of temperature on bitumen-water end point relative permeabilities and saturations. *J. Can. Pet. Technol.* **1986**, *25*, 5. [[CrossRef](#)]
42. Poston, S.; Ysrael, S.; Hossain, A.; Montgomery, E., III. The effect of temperature on irreducible water saturation and relative permeability of unconsolidated sands. *Soc. Pet. Eng. J.* **1970**, *10*, 171–180. [[CrossRef](#)]
43. Rosman, A. Experimental studies of low IFT displacement by CO₂ injection. In Proceedings of the Annual Fall Technical Conference and Exhibition, Denver, CO, USA, 9–12 October 1977.
44. Zuo, Y.-X.; Stenby, E.H. Prediction of interfacial tensions of reservoir crude oil and gas condensate systems. *SPE J.* **1998**, *3*, 134–145. [[CrossRef](#)]
45. Navascues, G. Liquid surfaces: Theory of surface tension. *Rep. Prog. Phys.* **1979**, *42*, 1131. [[CrossRef](#)]
46. Fulcher, R., Jr.; Ertekin, T.; Stahl, C. Effect of capillary number and its constituents on two-phase relative permeability curves. *J. Pet. Technol.* **1985**, *37*, 249–260. [[CrossRef](#)]
47. Harbert, L. Low interfacial tension relative permeability. In Proceedings of the Annual Technical Conference and Exhibition, San Francisco, CA, USA, 5–8 October 1983.
48. Asar, H.; Handy, L.L. Influence of interfacial tension on gas/oil relative permeability in a gas-condensate system. *SPE Reserv. Eng.* **1988**, *3*, 257–264. [[CrossRef](#)]
49. Honarvar, B.; Azdarpour, A.; Karimi, M.; Rahimi, A.; Afkhami Karaei, M.; Hamidi, H.; Ing, J.; Mohammadian, E. Experimental investigation of interfacial tension measurement and oil recovery by carbonated water injection: A case study using core samples from an Iranian carbonate oil reservoir. *Energ. Fuels* **2017**, *31*, 2740–2748. [[CrossRef](#)]
50. Yang, D.; Tontiwachwuthikul, P.; Gu, Y. Interfacial tensions of the crude oil + reservoir brine + CO₂ systems at pressures up to 31 MPa and temperatures of 27 °C and 58 °C. *J. Chem. Eng. Data* **2005**, *50*, 1242–1249. [[CrossRef](#)]
51. Chalbaud, C.; Robin, M.; Egermann, P. Interfacial tension of brine CO₂ systems under reservoirs conditions. In Proceedings of the Annual Technical Conference and Exhibition, San Antonio, TX, USA, 24–27 September 2006.
52. Wan, T.; Yang, S.; Wang, L.; Sun, L. Experimental investigation of two-phase relative permeability of gas and water for tight gas carbonate under different test conditions. *Oil Gas Sci. Technol.* **2019**, *74*, 23. [[CrossRef](#)]
53. Hemmati-Sarapardeh, A.; Ayatollahi, S.; Ghazanfari, M.-H.; Masihi, M. Experimental determination of interfacial tension and miscibility of the CO₂–crude oil system; temperature, pressure, and composition effects. *J. Chem. Eng. Data* **2013**, *59*, 61–69. [[CrossRef](#)]
54. Saraf, D.N.; McCaffery, F.G. *Two-and Three-Phase Relative Permeabilities: A Review*; Petroleum Recovery Institute: Calgary, AB, Canada, 1981.
55. Pruteanu, C.G.; Ackland, G.J.; Poon, W.C.; Loveday, J.S. When immiscible becomes miscible—Methane in water at high pressures. *Sci. Adv.* **2017**, *3*, e1700240. [[CrossRef](#)] [[PubMed](#)]
56. Leverett, M.C. Flow of oil-water mixtures through unconsolidated sands. *Trans. AIME* **1939**, *132*, 149–171. [[CrossRef](#)]
57. Leverett, M.; Lewis, W. Steady flow of gas-oil-water mixtures through unconsolidated sands. *Trans. AIME* **1941**, *142*, 107–116. [[CrossRef](#)]
58. Yuster, S. Theoretical considerations of multiphase flow in idealized capillary systems. In Proceedings of the Third World Petroleum Congress, Hague, The Netherlands, 28 May–6 June 1951; pp. 437–445.
59. Wyckoff, R.; Botset, H. The flow of gas-liquid mixtures through unconsolidated sands. *Physics* **1936**, *7*, 325–345. [[CrossRef](#)]
60. Craig, F.; Forrester, F. *The Reservoir Engineering Aspects of Waterflooding*; Society of Petroleum Engineers: New York, NY, USA, 1975; Volume 3.
61. Doherty, H.L. *Memorial Fund of AIME*; Society of Petroleum Engineers: New York, NY, USA, 1971; Volume 3.
62. Sandberg, C.; Gournay, L.; Sippel, R. *The Effect of Fluid-Flow Rate and Viscosity on Laboratory Determinations of Oil-Water Relative Permeabilities*; Society of Petroleum Engineers: New York, NY, USA, 1958.

63. Odeh, A.S. *Effect of Viscosity Ratio on Relative Permeability (Includes Associated Paper 1496-G)*; Society of Petroleum Engineers: New York, NY, USA, 1959.
64. Baker, P. Discussion of effect of viscosity ratio on relative permeability. *J. Pet. Technol.* **1960**, 219, 65.
65. Downie, J.; Crane, F. Effect of viscosity on relative permeability. *Soc. Pet. Eng. J.* **1961**, 1, 59–60. [[CrossRef](#)]
66. Niz Velásquez, E.; Niz Velasquez, E. *A Numerical and Physical Study of Relative Permeability in High-Pressure Air Injection Process*; University of Calgary: Calgary, AB, Canada, 2009.
67. Donaldson, E.C.; Thomas, R.D.; Lorenz, P.B. Wettability determination and its effect on recovery efficiency. *Soc. Pet. Eng. J.* **1969**, 9, 13–20. [[CrossRef](#)]
68. Gao, S.; Meegoda, J.N.; Hu, L. Simulation of dynamic two-phase flow during multistep air sparging. *Trans. Porous Med.* **2013**, 96, 173–192. [[CrossRef](#)]
69. Xia, H.; Wang, D.; Wu, W.; Jiang, H. Effect of the visco-elasticity of displacing fluids on the relationship of capillary number and displacement efficiency in weak oil-wet cores. In Proceedings of the Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, 30 October–1 November 2007.
70. Nazari, J.; Nasiry, F.; Seddiqui, N.; Honma, S. Influence of relative permeability and viscosity ratio on oil displacement by water in petroleum reservoir. *Proc. Schl. Eng. Tokai Univ.* **2015**, 40, 15–20.
71. Peters, E.J.; Flock, D.L. The onset of instability during two-phase immiscible displacement in porous media. *Soc. Pet. Eng. J.* **1981**, 21, 249–258. [[CrossRef](#)]
72. Johnson, E.; Bossler, D.; Bossler, V. *Calculation of Relative Permeability from Displacement Experiments*; Society of Petroleum Engineers: New York, NY, USA, 1959.
73. Jiang, G. *Gas Wettability of Reservoir Rock Surfaces with Porous Media*; Gulf Professional Publishing: Houston, TX, USA, 2018.
74. Moore, T.; Slobod, R. The effect of viscosity and capillarity on the displacement of oil by water. *Prod. Mon.* **1956**, 20, 20–30.
75. Wagner, O.; Leach, R. Improving oil displacement efficiency by wettability adjustment. *Trans. AIME* **1959**, 216, 65–72. [[CrossRef](#)]
76. Froning, H.; Leach, R. Determination of chemical requirements and applicability of wettability alteration flooding. *J. Pet. Technol.* **1967**, 19, 839–843. [[CrossRef](#)]
77. Penny, G.; Conway, M.; Briscoe, J. Enhanced load water-recovery technique improves stimulation results. In Proceedings of the Proceedings of the Annual Technical Conference and Exhibition, San Francisco, CA, USA, 5–8 October 1983.
78. Conway, M.W.; Smith, K.; Thomas, T.; Schraufnagel, R.A. The effect of surface active agents on the relative permeability of brine and gas in porous media. In Proceedings of the International Symposium on Oilfield Chemistry, San Antonio, TX, USA, 14–17 February 1995.
79. Al-Siyabi, Z.; Danesh, A.; Tohidi, B.; Todd, A. Measurement of gas-oil contact angle at reservoir conditions. In Proceedings of the 9th European Symposium on Improved Oil Recovery (IOR 1997), Hague, The Netherlands, 20–22 October 1997.
80. Morrow, N.; McCaffery, F. *Displacement Studies in Uniformly Wetted Porous Media*; Academic Press: New York, NY, USA, 1978; Volume 289.
81. Zisman, W.A. Relation of the equilibrium contact angle to liquid and solid constitution. *Adv. Chem.* **1964**. [[CrossRef](#)]
82. Dake, L. The Practice of Reservoir Engineering. In *Developments in Petroleum Science*; Elsevier Science and Technology: Amsterdam, The Netherlands, 1994; pp. 370–371.
83. Li, K.; Firoozabadi, A. Phenomenological modeling of critical condensate saturation and relative permeabilities in gas/condensate systems. *SPE J.* **2000**, 5, 138–147. [[CrossRef](#)]
84. Habowski, E. *The Effects of Large Temperature Change on Relative Permeability Ratios*; Pennsylvania State University: Pennsylvania, PA, USA, 1966.
85. Wang, W.; Gupta, A. Investigation of the effect of temperature and pressure on wettability using modified pendant drop method. In Proceedings of the Annual Technical Conference and Exhibition, Dallas, TX, USA, 22–25 October 1995.
86. Karyampudi, R. Evaluation of cyclic steam performance and mechanisms in a mobile heavy oil reservoir at Elk point thermal pilot. *J. Can. Pet. Technol.* **1995**, 34, 1. [[CrossRef](#)]
87. Blevins, T.; Duerksen, J.; Ault, J. Light-oil steamflooding an emerging technology. *J. Pet. Technol.* **1984**, 36, 1115–1122. [[CrossRef](#)]

88. Escrochi, M.; Nabipour, M.; Ayatollahi, S.S.; Mehranbod, N. Wettability alteration at elevated temperatures: The consequences of asphaltene precipitation. In Proceedings of the International Symposium and Exhibition on Formation Damage Control, Lafayette, LA, USA, 13–15 February 2008.
89. Larsen, J.K.; Fabricius, I.L. Interpretation of water saturation above the transitional zone in chalk reservoirs. *SPE Reserv. Eval. Eng.* **2004**, *7*, 155–163. [[CrossRef](#)]
90. Tang, G.-Q.; Firoozabadi, A. Effect of pressure gradient and initial water saturation on water injection in water-wet and mixed-wet fractured porous media. *SPE Reserv. Eval. Eng.* **2001**, *4*, 516–524. [[CrossRef](#)]
91. Wheaton, R. *Fundamentals of Applied Reservoir Engineering: Appraisal, Economics and Optimization*; Gulf Professional Publishing: Huston, TX, USA, 2016.
92. Narahara, G.; Pozzi, A., Jr.; Blackshear, T., Jr. Effect of connate water on gas/oil relative permeabilities for water-wet and mixed-wet berea rock. *Adv. Technol. Series* **1993**, *1*, 114–122. [[CrossRef](#)]
93. Corey, A.T. The interrelation between gas and oil relative permeabilities. *Prod. Mon.* **1954**, *19*, 38–41.
94. Moss, J.; White, P.; McNiel, J., Jr. *In Situ Combustion Process-Results of a Five-Well Field Experiment in Southern Oklahoma*; Society of Petroleum Engineers: New York, NY, USA, 1959.
95. Naar, J.; Henderson, J. An imbibition model—Its application to flow behavior and the prediction of oil recovery. *Soc. Pet. Eng. J.* **1961**, *1*, 61–70. [[CrossRef](#)]
96. Davidson, L. The effect of temperature on the permeability ratio of different fluid pairs in two-phase systems. *J. Pet. Technol.* **1969**, *21*, 1037–1046. [[CrossRef](#)]
97. Lo, H.Y.; Mungan, N. Effect of temperature on water-oil relative permeabilities in oil-wet and water-wet systems. In Proceedings of the Fall Meeting of the Society of Petroleum Engineers of AIME, Las Vegas, NV, USA, 30 September–3 October 1973.
98. Kumar, S.; Jain, R.; Chaudhary, P.; Mahto, V. Development of inhibitive water based drilling fluid system with synthesized graft copolymer for reactive Indian shale formation. In Proceedings of the SPE Oil and Gas India Conference and Exhibition, Mumbai, India, 4–6 April 2017.

© 2020 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<http://creativecommons.org/licenses/by/4.0/>).