Gas/Oil-Relative Permeabilities

Subjects: Energy & Fuels
Contributor: Saket Kumar

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. Definition

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.

2. 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][5][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][9][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][14][15][16][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**
Muqeem (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**

Authors	Year	Measurement Techniques	Porous Media	Type of System	Temperature Range (°C)	Effect of Temperature on Relative Permeability
Modaresghazani (Ph.D. Thesis) [16]	2015	Steady- and unsteady-state	Sand pack	Oil/Gas	Not Reported	Both k_{ro} and k_{rg} were affected

3. Data, Model, Applications and Influences

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

3.1.1. Irreducible Water Saturation

A few studies [18][19][20] 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 [21] postulated that irreducible water saturation can also be related to the wettability of the formation rock. Narahara et al. [22] 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.

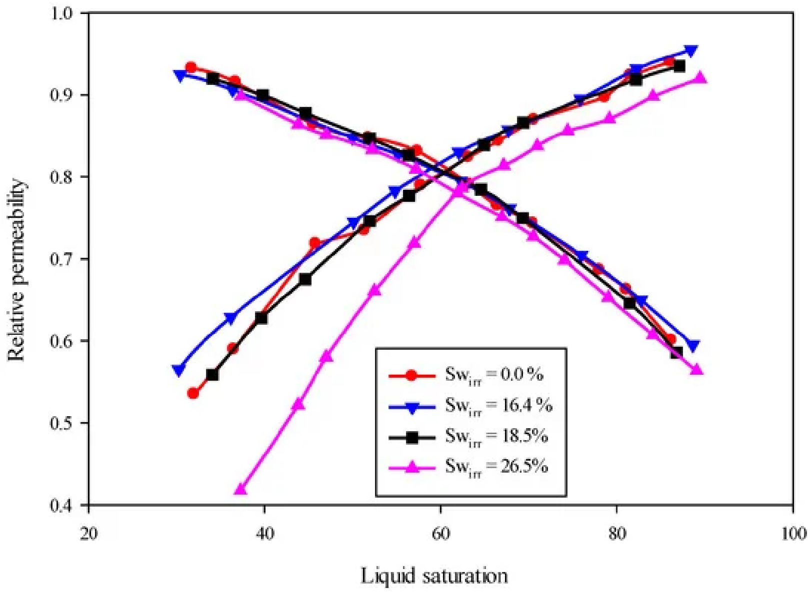

Figure 6. Effect of irreducible water saturation on two-phase gas/oil-relative permeability [22].

Corey [23] simplified the analytical expression given by Kozeny–Carman for relating the gas/liquid-relative permeability to fluid saturation. Later, McNiel and Moss [24] extended the work carried out by Corey [23] 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 [25] imbibition model suggests the possibility that the irreducible water saturation might be a function of temperature as well. Davidson [26] 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. [27]. 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. [22]	**1993**	**0–26.5**	**Oil-relative permeability changed and no effect on gas-relative permeability has been observed**
Corey [23]	**1954**	**N/R**	**Liquid-relative permeability has been affected**
Moss and McNiel [24]	**1959**	**0–13**	**Relative permeability curves to both the phases gas and oil has been changed**
Naar and Henderson's [25]	**1961**	**6–18**	**N/R**
Davidson [26]	**1969**	**4–4.12**	**N/R**
Lo et al. [27]	**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.

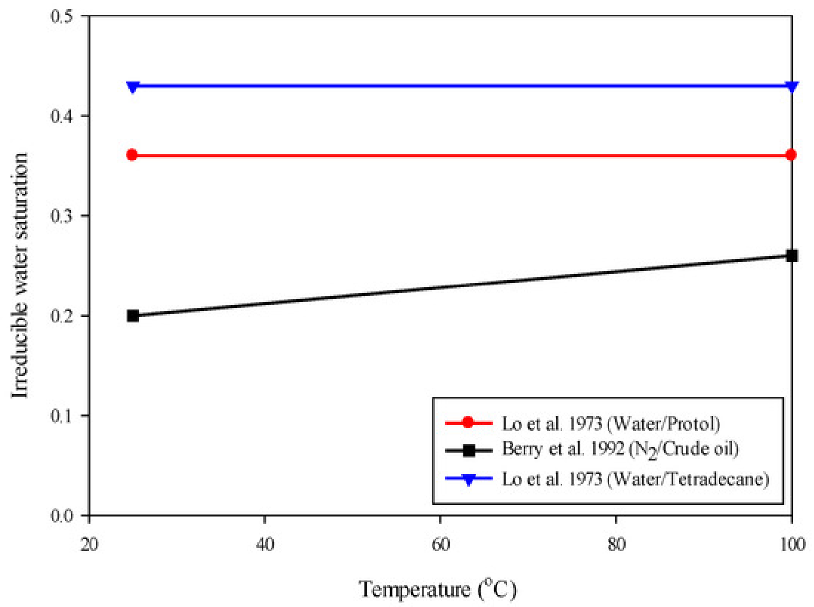

Figure 7. Effect of temperature on irreducible water saturation, reported by Lo et al. [27] and Berry et al. [14].

Esmaeili et al. [28] 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 [29][30]. 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.

3.1.2. 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 [28], at least for the oil/water system. Nonetheless, several studies reported no change in residual oil saturation with temperature [28]. 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 [31] 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. [32] also found that an increase in temperature lowered the surface tension and residual oil saturation. Yang et al. [33] conducted an experiment with CO_2 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 [33]. Chalbaud et al. [34] have supported this hypothesis by extending the same test to 100 °C and observed similar results as Yang et al. [33]. Bachu and Bennion [35] 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 [35]. Honarvar et al. [36] 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.

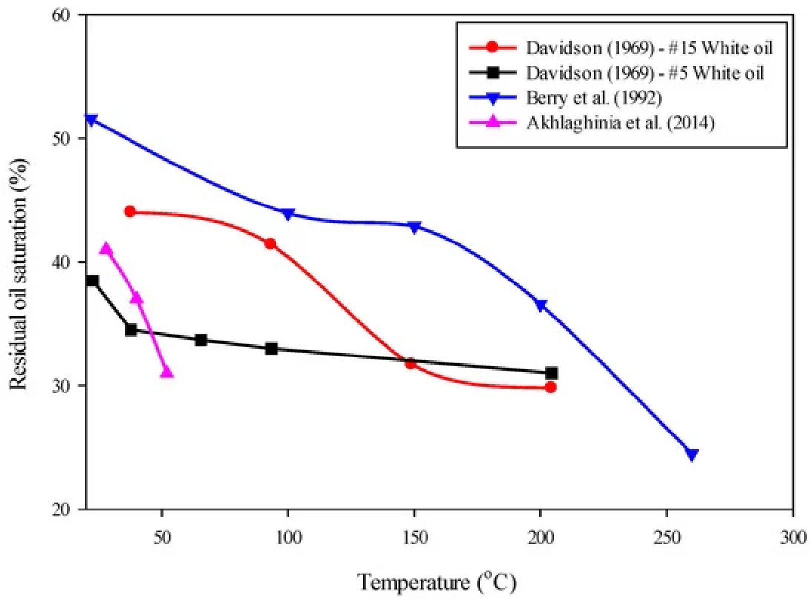

Figure 8. Effect of temperature on residual oil saturation in the gas/oil system.

Davidson [26] 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 [26]. 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 CH_4/CO_2 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. [28] 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.

3.1.3. 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 [37]. 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. [38] 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.

References

1. Eshragh Ghoodjani; Riyaz Kharrat; Manouchehr Vossoughi; Seyed Hamed Bolouri; A Review on Thermal Enhanced Heavy Oil Recovery from Fractured Carbonate Reservoirs. *Journal of Petroleum & Environmental Biotechnology* **2011**, *2*, 1-7, 10.4172/2157-7463.1000109.
2. Qi Jiang; Bruce Thornton; Jen Russel-Houston; Steve Spence; Review of Thermal Recovery Technologies for the Clearwater and Lower Grand Rapids Formations in the Cold Lake Area in Alberta. *Journal of Canadian Petroleum Technology* **2010**, *49*, 2-13, 10.2118/140118-pa.
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.
5. Hamouda, A.; Karoussi, O. Effect of temperature, wettability and relative permeability on oil recovery from oil-wet chalk. Energies 2008, 1, 19–34.
6. Punase, A.; Zou, A.; Elputranto, R. How do thermal recovery methods affect wettability alteration? J. Pet. Eng. 2014, 2014.
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. E. A. Letham; R. M. Bustin; Klinkenberg gas slippage measurements as a means for shale pore structure characterization. *Geofluids* **2015**, *16*, 264-278, 10.1111/gfl.12147.
10. Keliu Wu; Xiangfang Li; Chaohua Guo; Chenchen Wang; Zhangxin Chen; A Unified Model for Gas Transfer in Nanopores of Shale-Gas Reservoirs: Coupling Pore Diffusion and Surface Diffusion. *SPE Journal* **2016**, *21*, 1583-1611, 10.2118/2014-1921039-pa.
11. Anderson, W.G; Wettability literature survey-part 6: The effects of wettability on waterflooding. *J. Pet. Technol.* **1987**, *39*, 1605–1622, .
12. S.E. Buckley; M.C. Leverett; Mechanism of Fluid Displacement in Sands. *Transactions of the AIME* **1942**, *146*, 107-116, 10.2118/942107-g.
13. Manoochehr Akhlaghinia; Farshid Torabi; Christine W. Chan; Experimental investigation of temperature effect on three-phase relative permeability isoperms in heavy oil systems. *Fuel* **2014**, *118*, 281-290, 10.1016/j.fuel.2013.10.049.
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. D.G. Longeron; Influence of Very Low Interfacial Tensions on Relative Permeability. *Society of Petroleum Engineers Journal* **1980**, *20*, 391-401, 10.2118/7609-pa.

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. Muqeem, M.A. Effect of Temperature on Three-Phase Relative Permeability. Ph.D. Thesis, University of Alberta, Edmonton, AB, Canada, 1996.
18. 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.
19. 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.
20. 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.
21. Craig, F.; Forrest, F. The Reservoir Engineering Aspects of Waterflooding; Society of Petroleum Engineers: New York, NY, USA, 1975; Volume 3.
22. Wheaton, R. Fundamentals of Applied Reservoir Engineering: Appraisal, Economics and Optimization; Gulf Professional Publishing: Huston, TX, USA, 2016.
23. G.M. Narahara; A.L. Pozzi; T.H. Blackshear; Effect Of Connate Water On Gas/Oil Relative Permeabilities For Water-Wet And Mixed-Wet Berea Rock. *SPE Advanced Technology Series* **1993**, *1*, 114-122, 10.2118/20503-pa.
24. Corey, A.T; The interrelation between gas and oil relative permeabilities. *Prod. Mon.* **1954**, *19*, 38–41, .
25. 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.
26. J. Naar; J.H. Henderson; An Imbibition Model - Its Application to Flow Behavior and the Prediction of Oil Recovery. *Society of Petroleum Engineers Journal* **1961**, *1*, 61-70, 10.2118/1550-g.
27. L.B. Davidson; The Effect of Temperature on the Permeability Ratio of Different Fluid Pairs in Two-Phase Systems. *Journal of Petroleum Technology* **1969**, *21*, 1037-1046, 10.2118/2298-pa.
28. Sajjad Esmaeili; Hemanta Sarma; Thomas Harding; Brij Maini; Review of the effect of temperature on oil-water relative permeability in porous rocks of oil reservoirs. *Fuel* **2019**, *237*, 91-116, 10.1016/j.fuel.2018.09.100.
29. 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.
30. 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.
31. Hamza Asar; Lyman L. Handy; Influence of Interfacial Tension on Gas/Oil Relative Permeability in a Gas-Condensate System. *SPE Reservoir Engineering* **1988**, *3*, 257-264, 10.2118/11740-pa.
32. 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, .
33. 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, .
34. 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.
35. Bachu, S.; Bennion, B; Effects of in-situ conditions on relative permeability characteristics of CO 2-brine systems. *Environ. Geol.* **2008**, *54*, 1707–1722, .
36. 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, .
37. B. Maini; Is It Futile to Measure Relative Permeability For Heavy Oil Reservoirs?. *Journal of Canadian Petroleum Technology* **1998**, *37*, 56–62, 10.2118/98-04-06.
38. Teng Wan; Shenglai Yang; Lu Wang; Liting Sun; Experimental investigation of two-phase relative permeability of gas and water for tight gas carbonate under different test conditions. *Oil & Gas Science and Technology – Revue d'IFP Energies nouvelles* **2019**, *74*, 23, 10.2516/ogst/2018102.