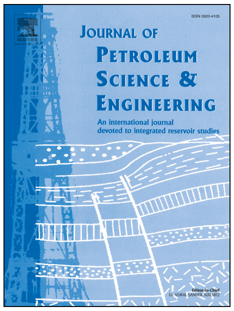

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A Mechanistic Model for Prediction of Three-Phase Flow in Petroleum Reservoirs

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Abstract

Multiphase flow in the porous media is of great interest for many engineering fields such as underground oil and gas reservoirs, environmental process (e.g. carbon dioxide (CO2) geological storage) and underground water resources remediation. Modelling of these process requires relative permeability (k_r) of each fluid as a function of the fluid saturation. The experimental measurement of the three-phase relative permeability is much more complex and time consuming process than the two-phase relative permeability. Hence, many correlations have been proposed in the oil industry for the calculation of the three-phase relative permeability using two-phase k_r data. However, most of the existing three-phase models ignore the physical mechanism underlying the multiphase flow in the porous media.

In this study, a novel mechanistic model is proposed to predict the three-phase relative permeability of the oil, water and gas in the petroleum reservoir (i.e. porous rock). The new idea is that the interaction between various fluids (i.e. oil, water and gas) and also the fluid saturation distribution are somehow considered in the estimation of the relative permeability. For this purpose, a new parameter named characteristic coefficient is introduced in the model. This parameter reflects the contribution of each fluid in controlling the flow of the other fluids. In other words, this factor is net impact of the various rock and fluid parameters (e.g. surface tension between fluids, wettability and saturation distribution) that all influence the flow in the porous media. This idea is taken from the glass-micro-model experiment that visualises the mechanism underlying the flow at the pore scale. Another feature of this method is that, at least one set of experimental three-phase k_r data is required to tune the characteristic coefficients. The estimated characteristic factors can then be employed to predict the three-phase relative permeability for the other saturation path.

The model is successfully validated against the experimentally measured three-phase relative permeability data.

Keywords: Porous media, Three-phase, Relative permeability, Petroleum

1- Introduction

The flow of immiscible fluids in the porous media is of great interest in many engineering process, such as underground hydrocarbon resources, storage of gas in geological formation due to environmental concern and contamination of underground water. The increasing demand for fossil fuel, on the one hand, and reduction of oil reserves in the world, on the other hand, have led many oil companies to develop enhanced oil recovery technique (EOR). Many of the EOR

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processes involve water and gas injection through the petroleum reservoir that result in development of three-phase flow (oil, water and gas) in the reservoir rock.

Flow of three immiscible fluids (i.e. oil, water and gas) may also occurs in the petroleum reservoir under different conditions such as in a reservoir having active aquifer and solution gas drive mechanism in which water and gas displace oil towards the production well.

Relative permeability is a key factor required for the simulation of the displacement process in the porous media in particular, oil and gas reservoirs. Relative permeability of a fluid is defined as the ratio of permeability (conductivity) of the pores occupied by that fluid at a given saturation to the absolute permeability of the entire porous medium. The absolute permeability is a function of rock alone whereas the relative permeability depends on the both rock and fluid condition (e.g. surface tension, wettability and pore size distribution). In other words, the relative permeability describes the extent to which one phase is hindered by the other phases in the pore spaces, and hence it can be formulated as a function of the fluid saturation.

The well-known complexity of the three-phase flow in the porous media is that an infinite numbers of the fluid saturation path or saturation combination can occur during a displacement process. The reason is that the degrees of freedom for the fluid saturation at three-phase condition are two independent fluid saturations. It means that by fixing one phase saturation the other two fluids saturations can get infinite values ($S_w + S_g + S_o = 1$). But on the other hand, the two phase flow has one degree of freedom such that by fixing one phase saturation the other fluid saturation is fixed as well (e.g. $S_w + S_o = 1$). Hence, the flow functions (k_r and P_c) in the three-phase circumstance may be function of two independent saturation (a surface plot in 3-dimenstional coordinate) whereas the two-phase relative permeability is function of the single saturation (a single curve in X-Y coordinate). It should be noted that three-phase k_r can be plotted in the different forms as shown in Figure 1 and Figure 2. Figure 1 (a) illustrates a schematic of three-phase k_{ro} as iso-perm curve (saturation paths which have equal k_{ro}) and Figure 1 (b) depicts an example of three-phase oil relative permeability in 3-D form plotted against the water and gas saturations. Figure 2 (a) demonstrates schematic of k_{ro} against its own saturation (S_o). Figure 2 (a) depicts that at a fixed value of S_o there might be several values for k_{ro} because in general the k_{ro} is function of two independent saturations (S_w and S_g). Figure 2 (b) shows k_{ro} against water saturation for various values of gas saturation which depicts k_{ro} is function of two independent saturations (S_w and S_g). As shown in Figure 2 (b), having different k_{ro} curves should not necessarily be attributed to the hysteresis effect.

Relative permeability of three-phase can be either measured in the laboratory by performing coreflood experiment or estimated using empirical correlations. Due to aforementioned complexity of the three-phase flow, the measurement of the relative permeability is costly and time-consuming process. The earliest three-phase measurement found in the literature belongs to Leverett and Lewis (1941). A comprehensive review of the experimental studies of the three-phase relative permeability is carried out by Alizadeh and Piri, (2014), recently. They reviewed the effects of saturation history, wettability, spreading, and layer drainage on the measured flow properties.

Due to the difficulties of the three-phase measurement, many researches have been directed towards development of an empirical correlation for estimation of the relative permeabilities (Corey, et al. (1956), Naar, and Wygal (1961), Land and Carlson (1968), Stone (1970), Stone

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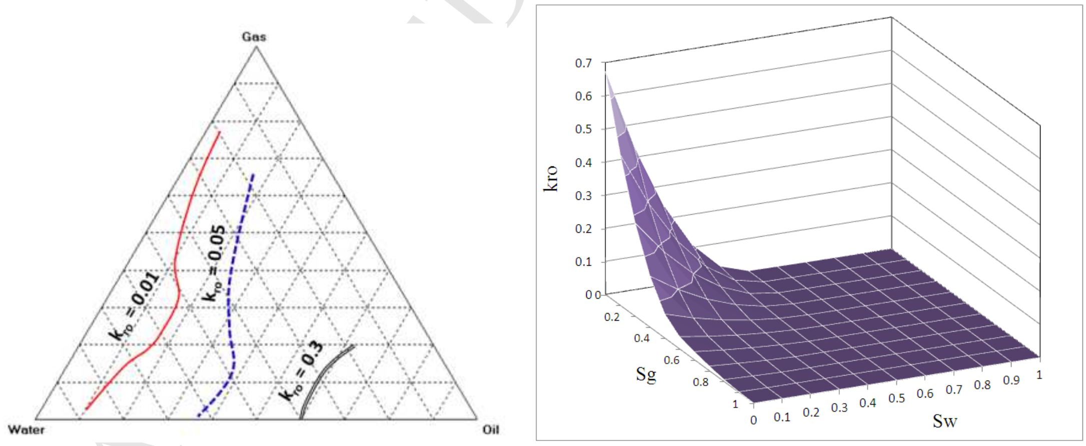
(1973), Baker (1988), Delshad, et al. (1989), Hustad and Hunsen (1995), Jeraud (1997), Blunt (1999), Moulu, et al. (1999), Hustad and Browning (2010), Shahverdi and Sohrabi (2013), Shahverdi and Sohrabi (2014), Beygi, et al. (2015),). Most of these models predict three-phase relative permeability by interpolating between two-phase relative permeability measured in the laboratory. The prime difference between the existing models is that they implements different interpolation technique (i.e. arithmetic or geometric) between two-phase data to estimate three-phase k_r. However, each model has been developed based on the limited experimental data and for the certain range of conditions. It should be noted that the most of the existing three-phase models ignore the physical mechanism underlying the three-phase flow in the porous media. The assessment of the three-phase correlations have revealed inadequacy of these models for prediction of experimental data (Element, et al. (2003), Delshad, et al. (1987), Shahverdi, et al.(2011a and 2011b))

In this research first, the most commonly used three-phase k_r correlations are briefly described. Then the theory and the principles of the new mechanistic model that incorporates the physics of the flow is presented. The new idea is that the interaction between various fluids (i.e. oil, water and gas) and also the fluid saturation distribution are somehow considered in the three-phase relative permeability model. For this purpose, a new parameter named characteristic coefficient is introduced in the model. This parameter reflects the contribution of each fluid in controlling of the flow of the other fluids. In other words, this factor is net impact of the various rock and fluid parameters (e.g. surface tension between fluids, wettability and saturation distribution) that influence the flow in porous media unlike the most of the existing models that ignore these effects. The validation of the model against various experimental data shows adequate accuracy in prediction of the three-phase relative permeability.



(a) *(b)*

Figure 1: An example of three-phase oil relative permeability plotted in the two forms. Figure (a) is three-phase k_{ro} as iso-perm curve (saturation paths which have the same k_{ro}). Figure (b) is three-phase k_{ro} in 3-D form plotted against water and gas saturation.

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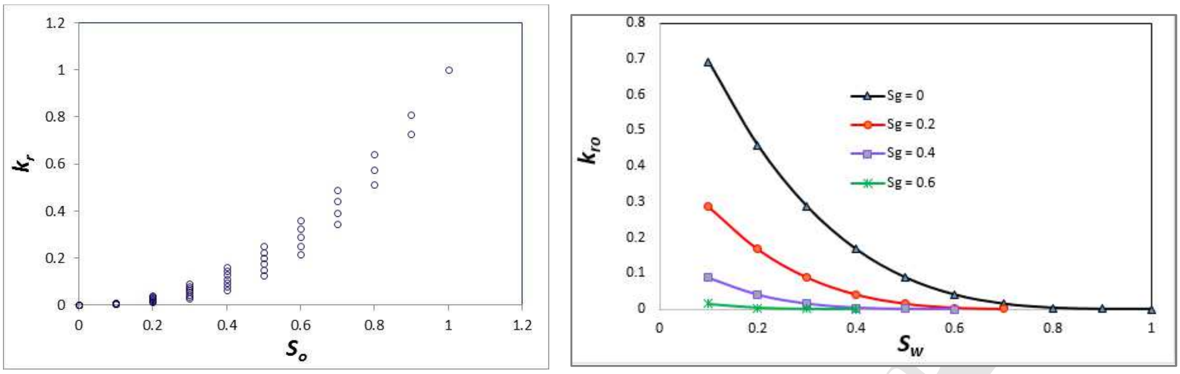

(a) (b)

Figure 2: An example of three-phase oil relative permeability plotted in two forms. Figure (a) shows k_{ro} *plotted against its own saturation* (S_o)*. Since* k_{ro} *is function of two independent saturation* (S_w *and* S_g) *at a fixed value of* S_o *there might be several values for* k_{ro}*. Figure (b) shows* k_{ro} *against water saturation for various values of gas saturation which depicts* k_{ro} *is function of two independent saturation (* S_w *and* S_g *).*

2- Review of the most famous three-phase k_r models

Many empirical correlations have been proposed so far for estimation of the three-phase relative permeability using two-phase k_r data. Here, we briefly review the most widely used models available in the commercial reservoir simulators (Eclipse, CMG) for simulation of the three-phase flow. The common aspect of all these models is that they all use two-phase relative permeability to calculate the three-phase kr data. In general, these models can be divided to two kinds, the STONE type and BAKER type models. The STONE type models was originally proposed by Stone (1970) named Stone-I model which uses the geometric averaging between two-phase relative permeability in the following form to calculate the three-phase k_{ro}:

$$k_{ro} = \frac{S_o^*}{(1-S_g^*)(1-S_w^*)} \times k_{rog} \times k_{row} \tag{1}$$

Where S_o^* is normalized saturation, k_{row} is oil relative permeability in the two-phase oil/water system and k_{rog} is two-phase oil relative permeability in the oil-gas system. The Stone-I model was then modified by Aziz and Settari (1979) taking into account the maximum oil relative permeability (k_{rocw}) at the maximum oil saturation (= $1- S_{wc}$) :

$$k_{ro} = k_{rocw} \times \frac{k_{rog}}{(1-S_g^*)k_{rocw}} \times \frac{k_{row}}{(1-S_w^*)k_{rocw}} \tag{2}$$

In the above equation, the two phase oil-water relative permeability (k_{row}) should be computed at the three-phase water saturation and the two phase oil-gas relative permeability (k_{rog}) should be looked up at the three-phase gas saturation.

This should be noted that Stone models were developed only for the prediction of the three-phase oil relative permeability. In this model, three-phase water and gas relative permeability are

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assumed to be same as two phase relative permeability in presence of oil. Stone (1972) modified his first model by a probability approach and incorporating water and gas relative permeability in the calculation of the three-phase k_{ro}:

$$k_{ro} = \left[\left(k_{rog} + k_{rg}\right)\left(k_{row} + k_{rw}\right) - k_{rw} - k_{rg}\right] \tag{3}$$

Although this model is a modified version of Stone-I model, usually it is less accurate than the Stone-I because, it results to the negative relative permeability for the oil phase at some range of saturation (Shahverdi, et al. (2011a)).

Hustad and Hold (1992) modified Stone-I model by introducing an exponent factor on the saturation term in equation (2) :

$$k_{ro} = \left[\frac{S_o^*}{\left(1 - S_g^*\right)\left(1 - S_w^*\right)}\right]^{\beta} \times \frac{k_{rog} \times k_{row}}{k_{rocw}} \tag{4}$$

The β term may be interpreted as a variable that changes between zero and one for low and high oil saturations respectively. The value of the exponent may be used, therefore, to match the predicted oil recovery to the observed data.

The most popular BAKER type models are Baker (1988), IKU (Hustad and Hansen (1995)) and ODD3P (Hustad and Browning (2010)). These models estimate the three-phase k_r for all mobile phases as a function of the two independent saturations. All these models apply an arithmetic averaging between two phase relative permeability to calculate the three-phase k_r. The Baker (1981) correlation for three-phase oil relative permeability is as follows:

$$k_{ro} = \left(\frac{(S_w - S_{wc})}{(S_w - S_{wc}) + S_g}\right) k_{row} + \left(\frac{S_g}{(S_w - S_{wc}) + S_g}\right) k_{rog} \tag{5}$$

Similar equations were developed for calculating water and gas relative permeability under three-phase flow condition. Unlike the Stone models, the two-phase oil relative permeability (k_{row} and k_{rog}) in the Baker model (Equation (5)) should be looked up at the three-phase oil saturation.

Hustad and Hansen (1995) proposed IKU model as a modified version of the BAKER method for estimation of three-phase oil, water and gas relative permeability. The IKU model suggests that the relative permeability is only affected by the mobile phase saturation rather than the total phase saturation. They suggested to compute two-phase k_r in the Baker model (e.g. k_{row}, k_{rog}) at a representative three-phase mobile saturation. For this purpose, a linear interpolation method was introduced for calculating maximum and minimum mobile phase saturation at the three-phase condition by using two-phase residual saturations. This approach is graphically illustrated in Figure 3 for the oil phase. The end-point saturation regarding to the oil phase at two-phase condition are residual oil in oil-gas (S_{org}), residual gas in oil-gas saturation (S_{gro}), residual oil in oil-water (S_{orw}) and residual water in oil-water system (S_{orw}). The oil saturation should be normalised by following equation:

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$$S_o^* = \frac{S_o - S_{omn}}{S_{omx} - S_{omn}} \tag{6}$$

Where S_{omn} and S_{omx} are minimum and maximum mobile saturation under three-phase condition. The normalized oil saturation then is used to obtain representative two-phase oil relative permeabilities (k_{row} and k_{rog}) for using in Equation (5) (without S_{wc}). The equivalent formulation is derived for calculation of the three-phase water and gas relative permeability.

Hustad and Browning (2010) developed the ODD3P model for calculating three-phase oil, water and gas relative permeability. This model is modified version of the IKU method taking into account the effect of the hysteresis and IFT (interfacial tension) variation between fluids. The full procedure for implementing this model is presented in the SPE paper 125429.

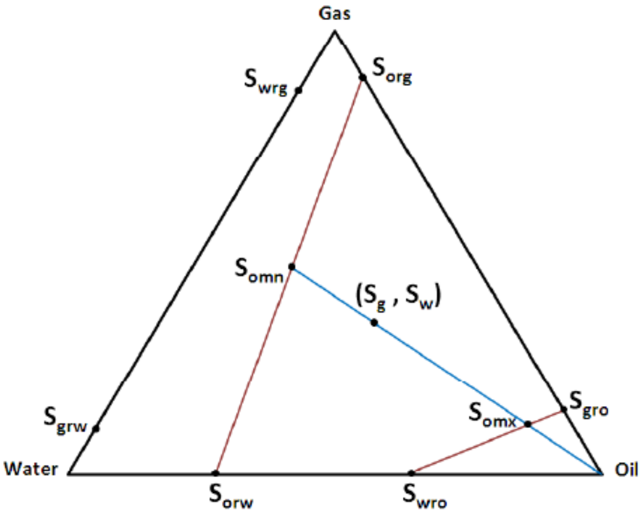

Figure 3: The method proposed by Hustad and Hansen (1995) for estimation of maximum (S_{omx}) and minimum (S_{omn}) three-phase mobile saturation using residual saturation (S_{orw}, S_{org}, S_{wro}, S_{wrg}, S_{grw}, S_{gro}) measured at the two-phase condition.

3- Motivation

In addition to the above models, many other correlations have been proposed for the prediction of three-phase relative permeability (Naar and Wygal (1961); Delshad, et al. (1987); Jerauld (1997); Blunt (2000)). Most of these models have just been verified for a limited three-phase k_r data. The validity of these models for the wide range of the rock and fluid conditions is questionable which may lead to an erroneous prediction for the three-phase k_r (Element, et al. (2003), Delshad, et al. (1987), Shahverdi, et al. (2011a and 2011b)).

As mentioned earlier, some of the old models (e.g. Stone, Baker) estimate the three-phase relative permeability by the simple averaging or interpolation between corresponding two-phase k_r (Equation (5) and (1)) without incorporating any mechanism of the flow. However, there are more recent models that incorporate different mechanisms occurring in three-phase flow (Beygi, et al. (2015), Hustad and Browning (2010), Blunt (2000)). Beygi, et al. (2015) proposed a

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correlation for the calculation of the three-phase k_r considering the compositional effect between fluids under different wettability conditions. Hustad and Browning (2010) proposed a fully coupled formulation for the three-phase capillary pressure and relative permeability incorporating the hysteresis and miscibility on both capillary pressure and relative permeability, simultaneously. Blunt (2000) presented an empirical model for the three-phase relative permeability that allows for the changes in the hydrocarbon composition and the trapping of oil, water, and gas. The model accounts the layer drainage mechanism in the oil relative permeability occurring at the low saturation.

However, in this study, we attempted to incorporate the mechanism of the flow different from the above-mentioned models. The main idea behind this model is that the various mechanisms and pertinent parameters affecting the multi-phase flow in the porous media (e.g. wettability, spreading coefficient, and pore size distribution) are reflected in the fluid distribution. For this purpose, a characteristics function with the new fluid saturation terminology is introduced in the model in order to account the impact of the fluid saturation in the estimation of relative permeability.

Many displacement mechanisms may take place during multiphase flow in the porous media which all are governed by the rock and fluid properties such as spreading coefficient, wettability and saturation distribution.

The fluid distribution in the porous media is a key factor in controlling the flow of the various phases and consequently the relative permeability functions. For instance, Figure 4 demonstrates a snapshot of a glass micro-model experiment under three-phase flow condition (water-alternating-gas (WAG) injection) which illustrates the distribution of the various fluids (i.e. oil, water and gas) in a porous media (Sohrabi, et al., 2000). As shown in this figure a cluster of the oil (shown by a pink circle) is dominated by only the water which implies the flow of this oil is only controlled by the water saturation. Whereas the other cluster (green circle) is connected with both water and gas hence the flow of this oil is affected by both water and gas saturation.

It can be concluded that the flow or relative permeability of each fluid in the three-phase condition is strongly affected by the distribution of the immiscible fluids in the pores. This fact is not properly taken into account in development of the existing three-phase kr models (e.g. Stone, Baker). The main inadequacy of the existing models is that they assume very simple fluid distribution for three-phase flow as illustrated in Figure 5 schematically. This figure depicts that the entire of the oil phase in the system is equally connected to (controlled by) the water and gas phases. This assumption implies that the flow of oil is equally governed by water and gas saturation (Figure 5) which is in contrast to the mechanism of three-phase flow described at the pore scale. In other words, the two-phase relative permeability in the Baker and Stone model (e.g. Equation (1) and (5)) are looked up at the total three-phase saturation as shown in Figure 5.

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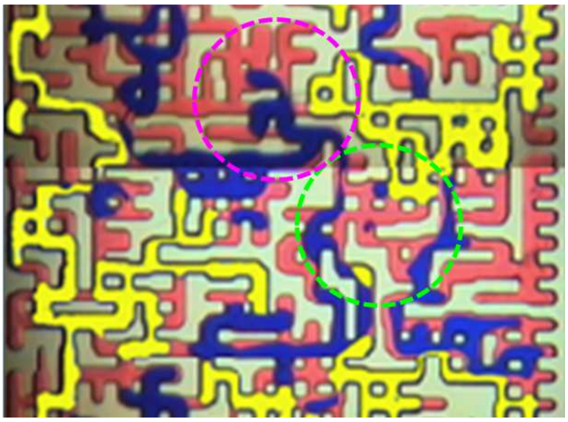

Figure 4: A snapshot of glass micromodel experiment (Sohrabi, et al. (2000)) shows the distribution of three-phases (oil, water and gas) in the Water-Alternating-Gas (WAG) injection. The oil, water and gas are presented by red, blue and yellow color, respectively.

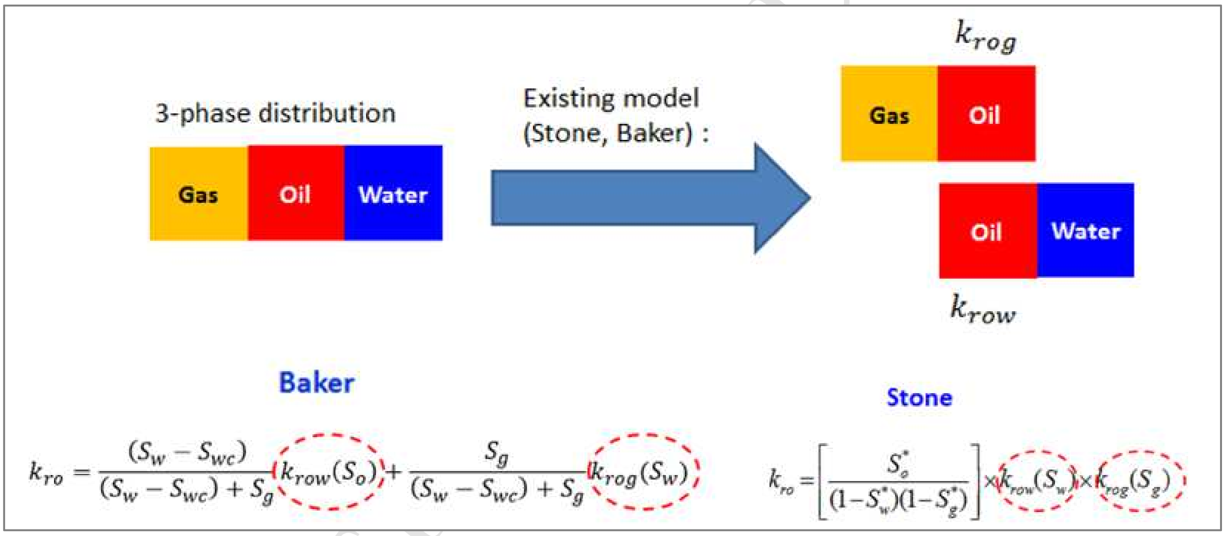

Figure 5: A schematic of three-phase fluid distribution in the porous media assumed in the existing models (e.g. Stone, Baker).

4- Theory

The more realistic pattern for the saturation distribution in the three-phase flow is to consider each of the immiscible fluids as two parts. As depicted in Figure 6 one part of the oil saturation is only connected to the water phase (S_{ow}) and the other part is connected only to the gas phase (S_{og}). The summation of two saturations S_{ow} and S_{og} may be less, equal or greater than S_o^{3Ph} (the total oil saturation at three-phase condition). Once this summation is less than S_o^{3Ph} it depicts that

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the part of oil is immobile whereas the case of summation greater than S_o^{3Ph}demonstrates the overlap between S_{ow} and S_{og}. While the summation of saturations (S_{ow} and S_{og}) is equal to the S_o^{3Ph} shows that the part of oil is controlled by water and the rest of oil is in connection with gas and hence, there is not any immobile or overlap saturation.

Now, considering this theory, the three-phase k_{ro} is combination of two-phase relative permeability of the oil to the gas (k_{rog}) and the oil to the water (k_{row}). However, the contribution of k_{row} and k_{rog} in the three-phase k_{ro} is not equal. Whereas the existing models assume equal impact for k_{rwo} and k_{rog} in estimation of 3-phase k_{ro} such that two-phase oil relative permeabilities (k_{row} and k_{rog}) are picked up at the same oil saturation (Figure 5). The evaluation of the existing models performed by the previous researchers (Delshad, et al. (1987), Hustad and Hunsen (1995), Hustad and Browning (2010), Shahverdi, et al.(2011a and 2011b) depicted that the Baker type model (arithmetic averaging) results in the better prediction for the three-phase relative permeability compared to the other existing models. Hence, we have used the arithmetic averaging relationship between two-phase and three-phase relative permeability as:

$$k_{ro} \propto \left(Ak_{row} + Bk_{rog}\right) \tag{7}$$

Where A and B are the weight factors reflecting the extent of impact for each of k_{row} and k_{rog} which affect the three-phase k_{ro}. Using saturation weight factor in the above equation:

$$k_{ro} = \frac{S_{wo}}{S_{wo} + S_{go}} k_{row}(S_{ow}) + \frac{S_{go}}{S_{wo} + S_{go}} k_{rog}(S_{og}) \tag{8}$$

As can be seen the k_{row} and k_{rog} in the above equation should be picked up at the representative two-phase saturation (S_{ow} and S_{og}). Also the saturation weight factors ($\frac{S_{wo}}{S_{wo}+S_{go}}$ and $\frac{S_{go}}{S_{wo}+S_{go}}$) are calculated using the representative two-phase saturation. The formulation and theory of the mechanistic model is illustrated schematically in Figure 7.

Similar theory and equation can be developed to obtain three-phase k_r of water and gas:

$$k_{rw} = \frac{S_{ow}}{S_{ow} + S_{gw}} k_{rwo}(S_{wo}) + \frac{S_{gw}}{S_{ow} + S_{gw}} k_{rwg}(S_{wg}) \tag{9}$$

$$k_{rg} = \frac{S_{og}}{S_{og} + S_{wg}} k_{rgw}(S_{gw}) + \frac{S_{wg}}{S_{og} + S_{wg}} k_{rgo}(S_{go}) \tag{10}$$

For determination of the representative saturations in Equations (8) to (10), (S_{ow} , S_{og} , S_{go} , S_{gw} , S_{wo} , S_{wg}), a simple linear relationship between two-phase and three-phase oil saturation is suggested as follows:

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$$S_{ow} = A_{ow} \times S_o^{3Ph} \tag{11}$$
$$S_{og} = A_{og} \times S_o^{3Ph} \tag{12}$$

Where A_{ow} and A_{og} are named characteristic coefficient for the three-phase flow which have a value between zero and one. This coefficient represents the extent of impact of water and gas phases that affects the oil relative permeability. When A_{ow} is equal to one, $S_{ow} = S_o^{3Ph}$, implying that entire of the oil phase is only in contact with the water and thus its flow (k_{ro}) is only affected by the water saturation. In this case the gas phase is not contributing in the flow of the oil. For the case that A_{ow} is equal to zero, the value of S_{ow} becomes zero hence, the water does affect the oil flow or the oil phase is fully governed by the gas phase saturation. The higher value of A_{ow} demonstrates the higher impact of the water phase in controlling the relative permeability of the oil and vice versa. Figure 8 shows an example of plot for S_{ow} and S_{og} versus S_o^{3Ph} based on the linear relationship proposed in Equation (11) and (12). This graph clearly illustrates the competition between the water and gas in displacing of the oil phase. As can be seen the slope of S_{og} curve (A_{og}) is greater than that of S_{ow} (A_{ow}) depicting that the oil relative permeability is more affected by the gas saturation than by the water phase. It should be noted that in the case of the two-phase oil-gas or oil-water system the characteristic coefficients (A_{ow} *and* A_{og}) become unity (black line in Figure 8). As mentioned earlier, the summation of A_{og} and A_{ow} is not necessarily equal to one because there might be an overlap between S_{og} and S_{ow} indicating that some part of oil is governed by the both water and gas phase saturation.

Equation (11) and (12) and above theory can similarly be developed for the water and gas phase:

$$S_{wo} = A_{wo} \times S_w^{3Ph} \tag{13}$$
$$S_{wg} = A_{wg} \times S_w^{3Ph} \tag{14}$$
$$S_{go} = A_{go} \times S_g^{3Ph} \tag{15}$$
$$S_{gw} = A_{gw} \times S_g^{3Ph} \tag{16}$$

The characteristic coefficients, A_{wo}, A_{wg}, A_{go} … etc. are functions of interfacial tension (IFT) between fluids, wettability and pore size distribution of rock which all affect the fluid distribution. For simplicity, in this study it is assumed that at a given condition of IFT, wettability and pore size the characteristic coefficients remain constant during the fluid flow. The characteristic coefficients can be tuned using a measured set of the three-phase relative permeability data in the combination with Equation (8), (9) and (10). In other words, this tuning is kind of inverse problem which estimate the characterization coefficients using an optimization technique (e.g. Genetic Algorithm). The objective function is the error between the measured and calculated relative permeability which should be minimized by tuning the characterization coefficients (A_{ij}). The estimated coefficient can then be employed in the model to calculate the three-phase relative permeability of the other saturation path. The algorithm for prediction of three-phase relative permeability using mechanistic model is described in Figure 9. The detailed procedure of Genetic algorithm for estimation of relative permeability are discussed in another publication (Shahverdi, et al., 2011).

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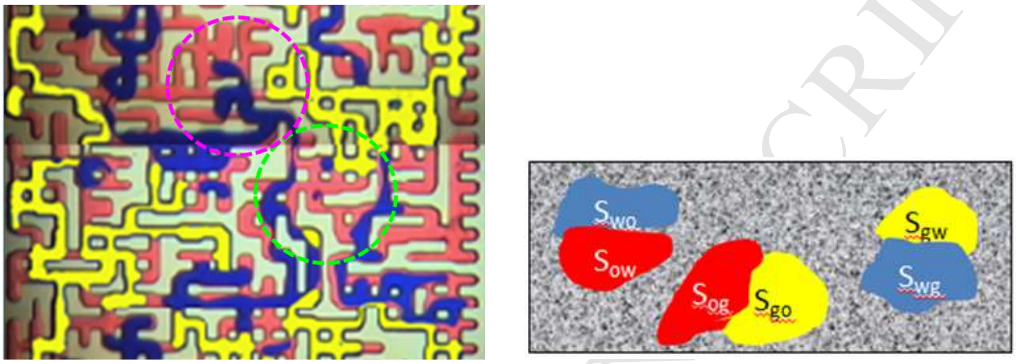
Obviously, a level of uncertainty may be associated to the estimated characteristic coefficients, A_{ij} and subsequently to the relative permeabilities. However, employing more measured data of the three-phase k_r for tuning of the characteristic coefficients, can reduce the degree of the uncertainty. Moreover, the characteristic coefficients can be used as a tuning factor in history matching of production and pressure data obtained from the reservoir. In absence of measured three-phase k_r data, a rough value based on the wettability and IFT condition of the fluids and porous media can be assigned to the characteristic coefficients.



(a) (b)

Figure 6: Figure (a) shows three-phase distribution in porous media obtained from glass micro-model experiment (Sohrabi, et al., 2000). Figure (b) present three-phase distribution considered in the mechanistic model.

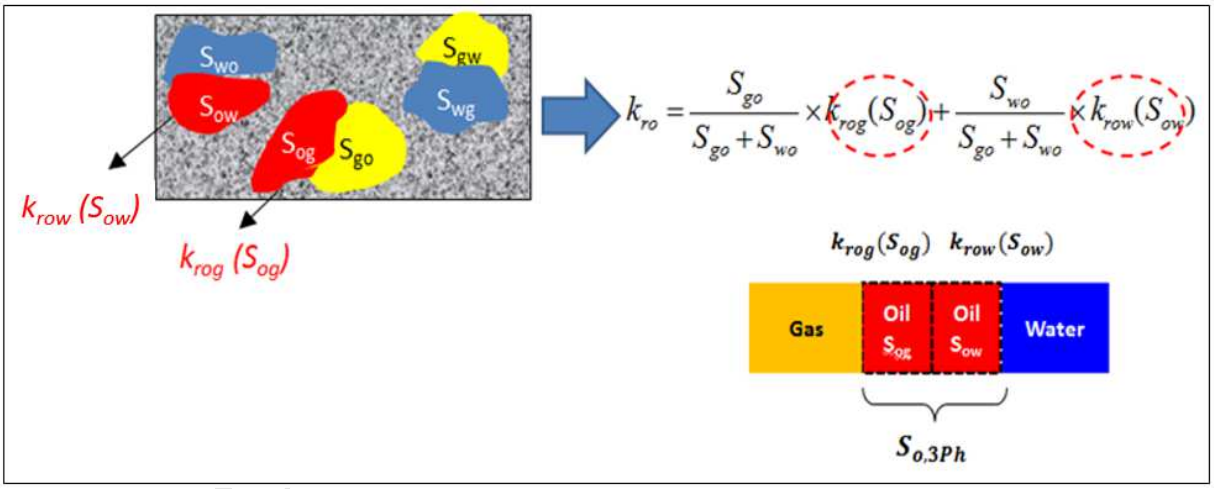


Figure 7: Theory and formulation of the mechanistic model for prediction of three-phase oil relative permeability.

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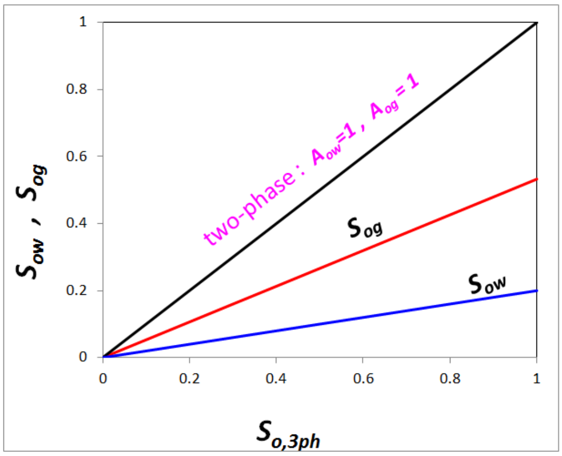

Figure 8: An example plot of S_{wo} *and* S_{og} *versus* $S_{o,3ph}$ *proposed by Equation (11) and (12). The slope of each curve represents the corresponding characteristic coefficients (*A_{ow} *,* A_{og}*). The black line with unite slope demonstrate the condition of two-phase flow (either oil-water system when* $A_{ow}=1$ *or oil-gas system when* $A_{og}=1$*) .*

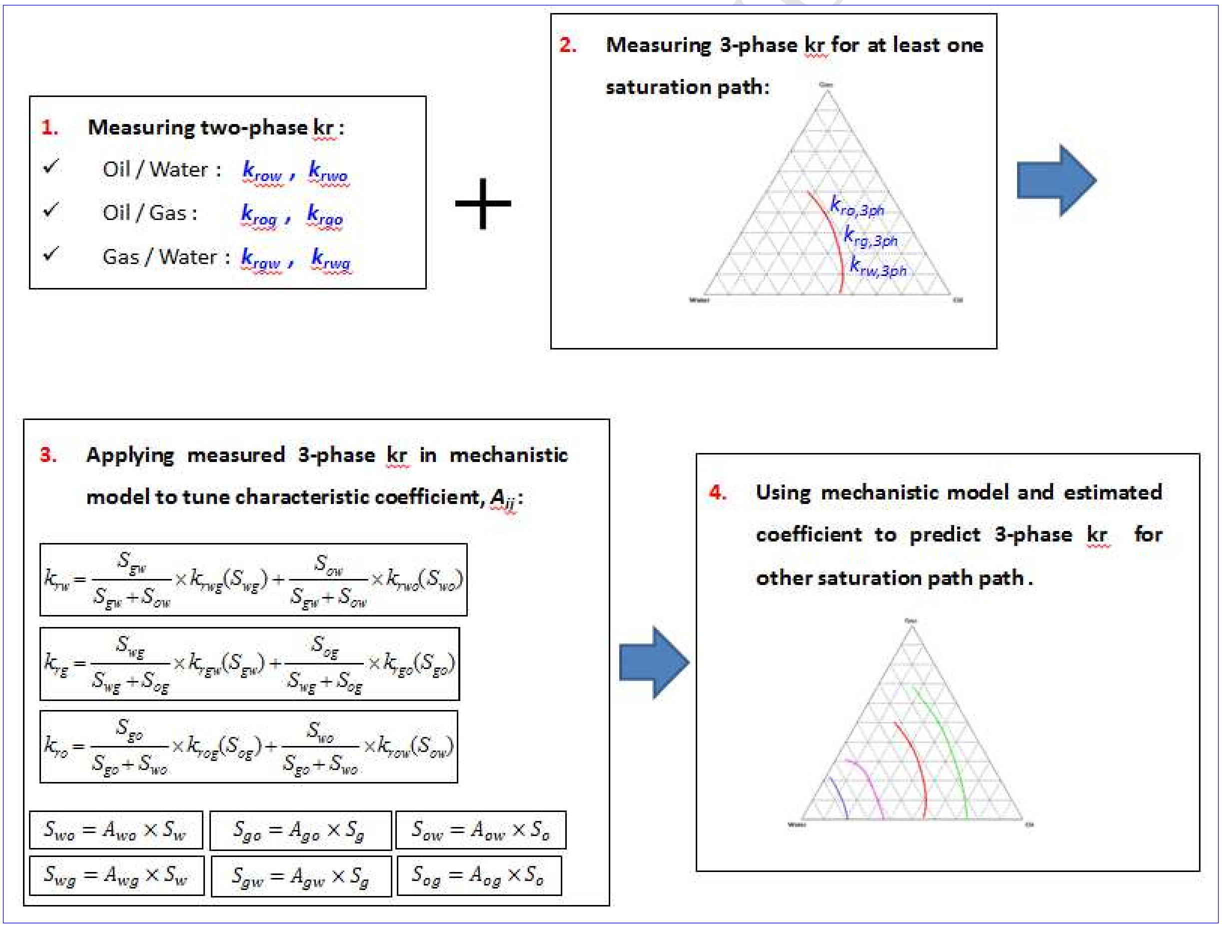

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Figure 9: Algorithm of implementing the mechanistic model for prediction of three-phase relative permeability.

5- Verification of the model

In this section, the three-phase relative permeability data obtained from the coreflood experiment (Oak (1989)) are used to validate the proposed model in this study. Oak (1989) performed a series of the steady-state experiment to obtain two-phase and three-phase relative permeability of a Berea sandstone rocks. The physical properties of the rock and fluid used in these experiments are provided in Table 1 and 2.

Three steady-state DDI (Decreasing water, Decreasing oil and Increasing gas saturation) test performed at the three-phase condition are selected from the Oak data. The saturation path met in these experiments are presented in Figure 10. As can be seen the initial saturation and saturation path of each test is totally different from the others. The three-phase relative permeability of the oil, water and gas for each experiment reported by Oak, will be compared with the calculated 3-phase k_r using mechanistic model later in this manuscript.

The two-phase relative permeability of the oil-gas, gas-water and oil-water system measured by the steady-state Oak experiment are reported in Figure 11 and Figure 12. This should be highlighted that the presented model in this research can be used for any three-phase process (e.g. IDD, DII, DID, IID ...). However, the input two-phase k_r data should be selected from an appropriate process (Drainage or imbibition) that corresponds three-phase saturation path. For instance, in the case of DDI process (Decreasing water, Decreasing oil and Increasing gas saturation; which gas displaces oil and water), the k_r of oil-gas and gas-water system should be selected from drainage process in which gas saturation is increasing.

These data as well as the three-phase relative permeability of the first DDI test (G1 in Figure 10) were used in combination with the mechanistic k_r model (equations (8), (9) and (10)) to obtain the characteristic coefficients (A_{ow}, A_{og}, A_{wo}, A_{wg}, A_{go}, A_{gw}). This procedure (as explained in step 3 of Figure 9) is a kind of inverse problem in which the 3-phase k_r are known and the characteristic coefficients are unknown. Hence, by using an optimization technique (e.g. Genetic Algorithm) the unknown characteristic coefficients can be estimated.

Table 1: Rock properties of Oak experiment.

Connate water saturation	Absolute Permeability(md)	Porosity	Core Length (cm)	Core Diameter(cm)
0.31	200	0.22	7.5	5

Table 2: Fluid properties of Oak experiment.

Phase	Water	Oil	Gas
Density ($\frac{gr}{cc}$)	1.00	0.83	0.22

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Viscosity (cp)	1.06	1.77	0.0187

6- Results and Discussion

Figure 13 and Figure 14 depict the experimental three-phase k_r of the first DDI test (G1) against the tuned relative permeability for oil, water and gas phase. As can be seen there is a good agreement between the experimental and calculated relative permeabilities of the first DDI. The characteristic coefficients estimated by this optimization is given in Table 3. The results of this table depicts that the A_{ow} is greater than the A_{og} hence the oil is more dominated by the water phase than by the gas phase. Also, the comparison between A_{wo} and A_{wg} in Table 3 demonstrates that the more fraction of the water saturation is governed by the oil and thus the gas phase has less contribution in controlling the flow of the water. Similarly, the comparison between A_{go} and A_{gw} substantiate that the gas is more governed by the oil than by the water.

The characteristic coefficients estimated in the previous step were then employed in the mechanistic model (equations (8), (9) and (10)) for the second and third DDI test (G2 and G3) to predict 3-phase kr of these experiments. Figure 15 demonstrates three-phase oil relative permeability versus oil saturation resulted from the second and third DDI experiment (G2 and G3) compared with those predicted by the mechanistic model. Figure 16 and Figure 17 present comparison between experimental and predicted three-phase k_r for the water and gas, respectively. Since the water relative permeabilities have low values (order of 10^{-3} to 10^{-4}) in Figure 16, this graph is plotted in semi-log scale to better investigate the measured against predicted k_{rw}. As shown in Figure 15 to Figure 17, the mechanistic model can adequately predict the three-phase relative permeability of experiments (G2 and G3). However, there are slight difference between measured and predicted relative permeability in Figure 15 to Figure 17 which may attributed to the uncertainty in the characteristic coefficients (A_{ij}) derived from optimization technique. For further investigation of the accuracy of the mode, the predicted three-phase k_r (oil, water and gas) by the model is plotted against experimentally measured k_r in Figure 18. The data points in this Figure belong to oil, water and gas relative permeability. As can be seen, the predicted k_r value are reasonably close to the straight line that highlights the good agreement between actual and estimated relative permeability.

In order to investigate the accuracy of the mechanistic model against the existing models, the Oak data was also estimated by the Baker and Stone model. Figure 19 presents the cross-plot for the Baker and Stone model. As can be seen both the Baker and Stone model significantly overestimate the actual three-phase relative permeability.

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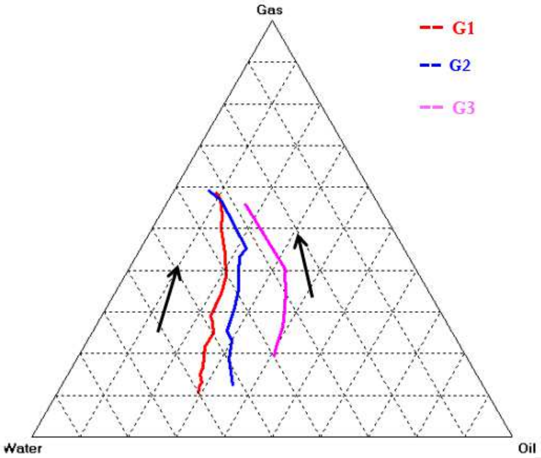
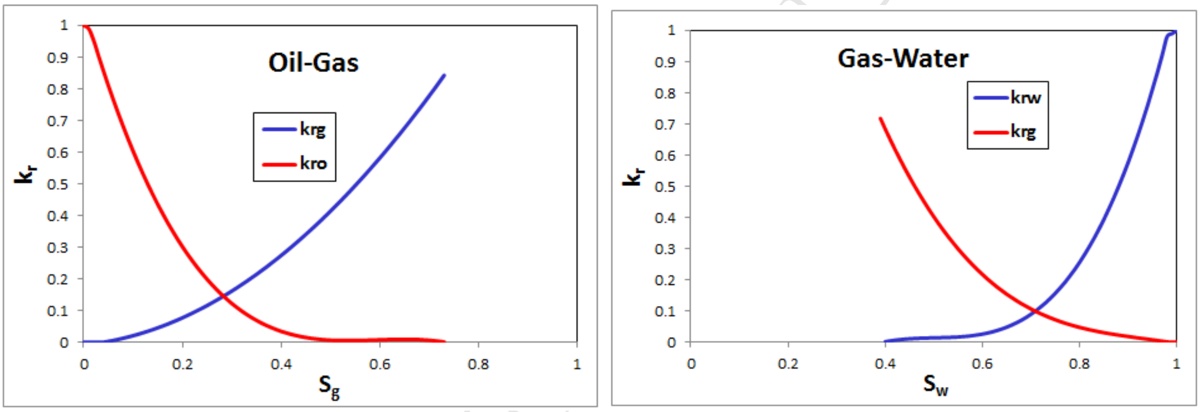


Figure 10: Saturation path of different DDI test (Oak (1989)) under three-phase condition. "G1", "G2" and "G3" stand for first, second and third DDI test, respectively.



(b) *(b)*

Figure 11: Two-phase oil-gas relative permeability versus gas saturation (picture a) and gas-water relative permeability versus water saturation (picture b) from the Oak experiment (Oak (1989)).

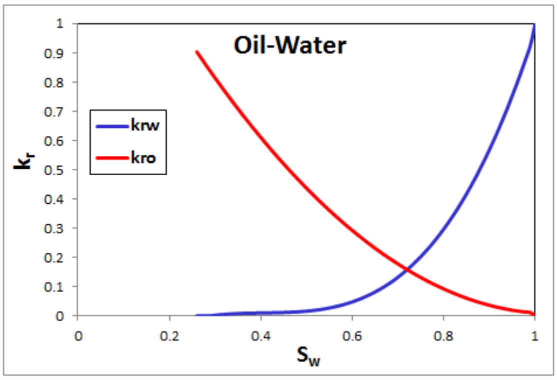


Figure 12: Two-phase oil-water relative permeability versus water saturation from the Oak experiment (Oak (1989)).

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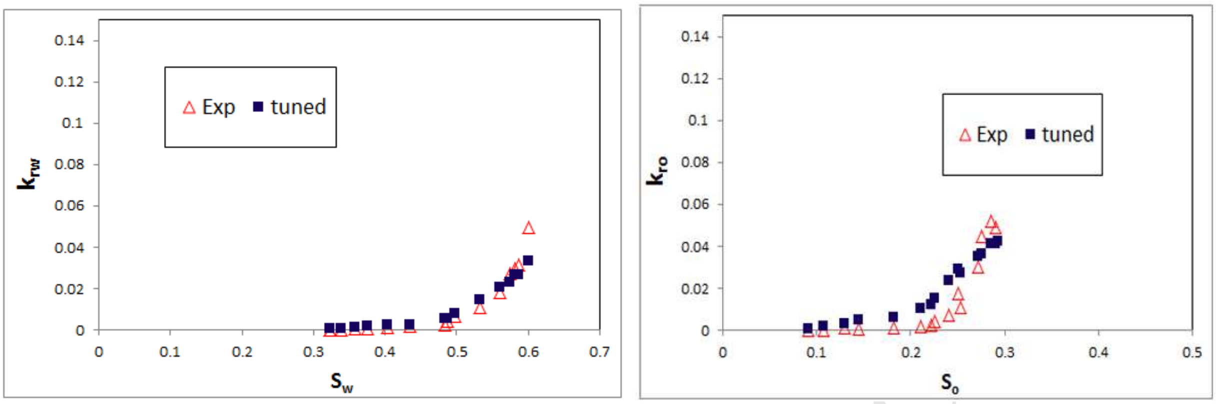

(a) *(b)*

Figure 13: Picture (a): Three-phase water relative permeability versus water saturation resulted from the first DDI (G1) of the Oak experiment (triangle points) and those obtained from the mechanistic model by tuning the characteristics coefficients (square points). Picture (b): Three-phase oil relative permeability versus oil saturation resulted from the first DDI (G1) of the Oak experiment (triangle points) and those obtained from the mechanistic model by tuning the characteristics coefficients (square points).

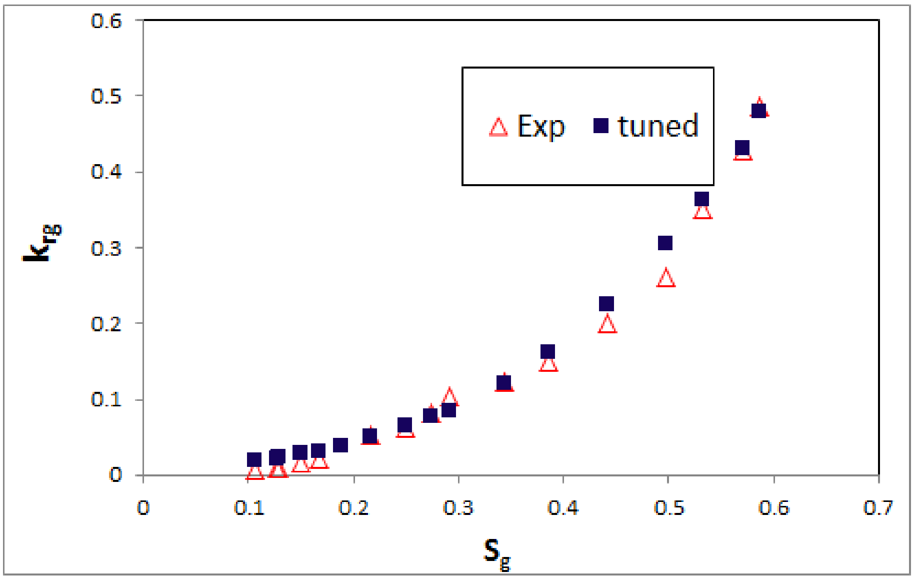

Figure 14: Three-phase gas relative permeability versus gas saturation resulted from the first DDI (G1) of the Oak experiment (triangle points) and those obtained from the mechanistic model by tuning the characteristics coefficients (square points).

Table 3: The characteristic coefficients estimated by tuning the 3-phase k_r of the G1 experiment.

Aog	**Aow**	**Ago**	**Agw**	**Awo**	**Awg**
0.1416	0.4375	0.9825	0.9032	0.9937	0.8304

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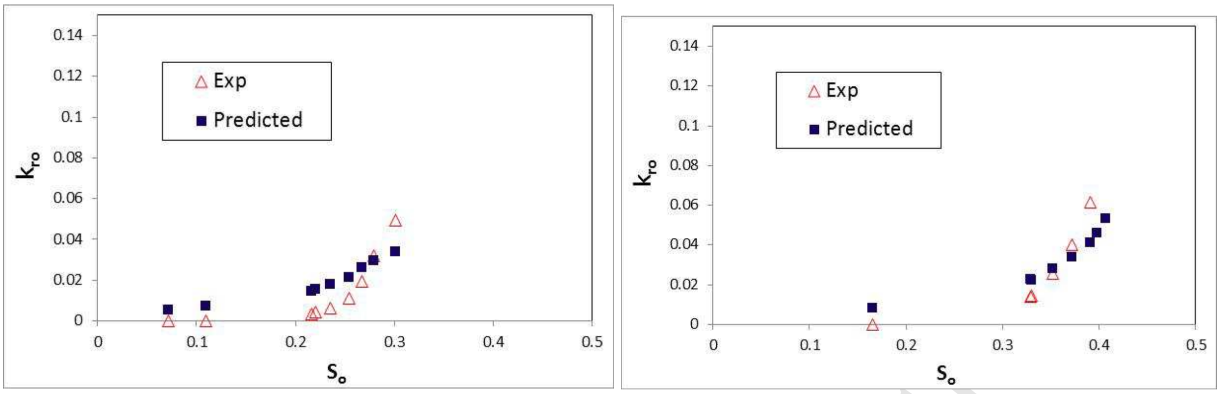
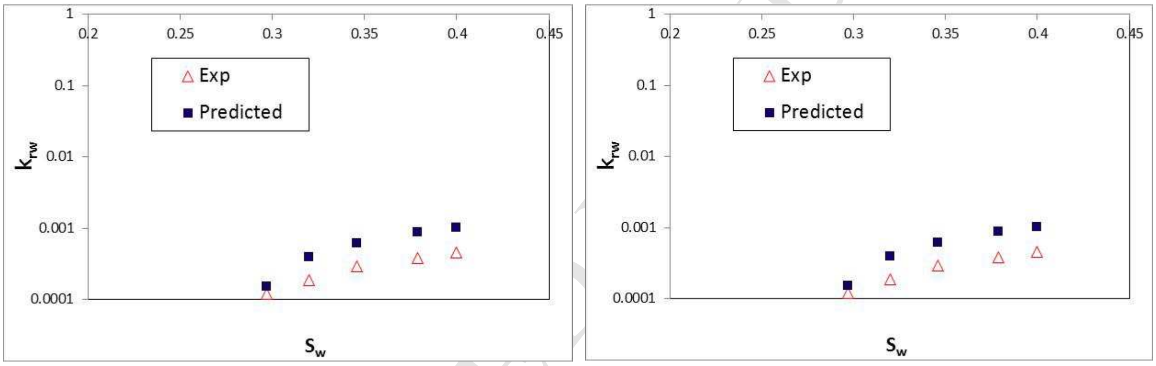


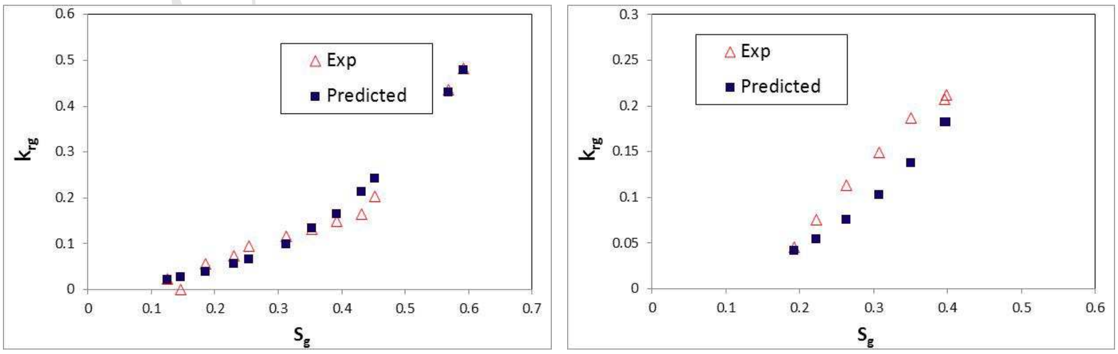
(a) *(b)*

Figure 15: Picture (a): Three-phase oil relative permeability versus oil saturation resulted from the second DDI (G2) of the Oak experiment and those obtained from the mechanistic model. Picture (b): Three-phase oil relative permeability versus oil saturation resulted from the third DDI test (G3)of the Oak experiment and those obtained from the mechanistic model.



(a) *(b)*

Figure 16: Picture (a): semi-log plot of three-phase water relative permeability versus water saturation resulted from the second DDI test (G2) of the Oak experiment and those obtained from the mechanistic model. Picture (b): semi-log plot of three-phase water relative permeability versus water saturation resulted from the third DDI test (G3) of the Oak experiment and those obtained from the mechanistic model.



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(a) *(b)*

Figure 17: Picture (a): Three-phase gas relative permeability versus gas saturation resulted from the second DDI test (G2) of the Oak experiment and those obtained from the mechanistic model. Picture (b): Three-phase gas relative permeability versus gas saturation resulted from the third DDI test (G3)of the Oak experiment and those obtained from the mechanistic model.

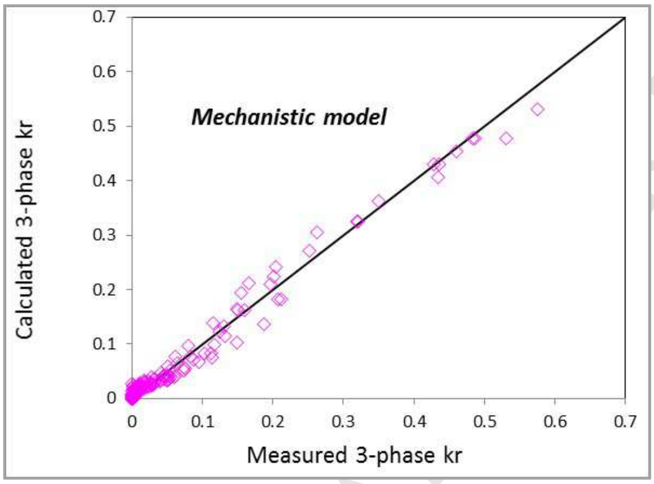

Figure 18: Cross-plot of the calculated three-phase relative permeability (by the mechanistic model) against the measured three-phase k_r of the Oak experiment.

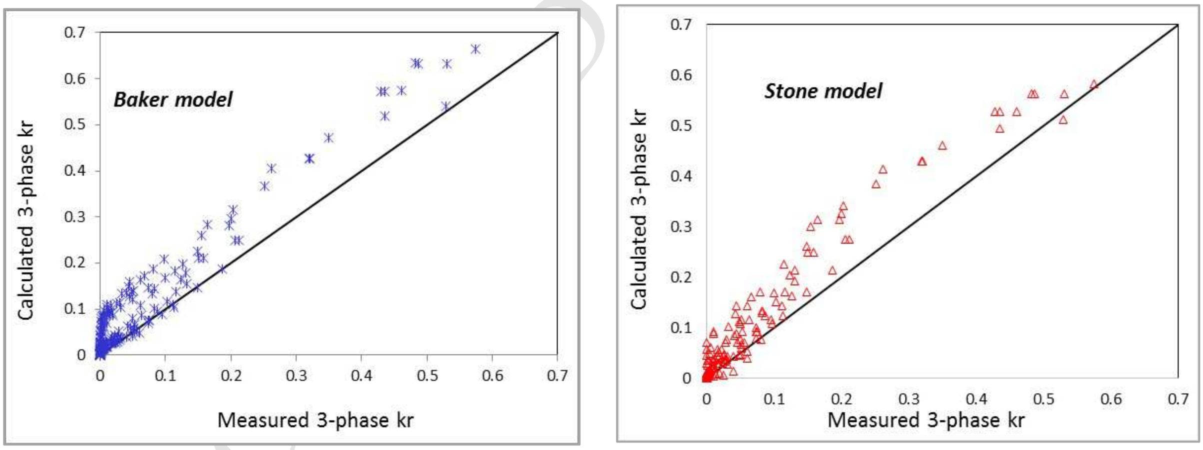

Figure 19: Cross-plot of the calculated three-phase relative permeability by Baker model (left picture) and Stone model (right picture) against the measured three-phase k_r of the Oak experiment.

7- Conclusions:

1. A new mechanistic model is proposed to predict the relative permeability of three immiscible fluids (i.e. oil, water and gas) in the porous media. This model attempts to incorporate the impact of the fluid distribution and physical mechanisms of the flow in

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the estimation of the relative permeability. This theory is well-matched with the physical mechanism underlying the flow at the pore scale which is observed in the glass micro-model experiment. Unlike, the most of the existing model estimates three-phase relative permeability only by interpolation between two-phase data without considering any physics of the flow.

2. A new parameter named characteristic coefficient is introduced in the model that reflects the interaction between fluids and also the fluid distribution. This parameter depends on the rock and fluid properties such as surface tension between fluids, wettability and saturation distribution.
3. The saturation distribution in porous media is controlled by surface and capillary forces (e.g. wettability and IFT) which all significantly affect three-phase flow parameters (k_r). One of the drawback of the existing models is that, the three-phase kr is calculated just by averaging between two-phase k_r without considering the physical mechanism occurring at three-phase condition. In fact, the fluid distribution in three-phase flow mechanism might be totally different from two-phase flow. Hence, the two-phase k_r alone cannot accurately predict the three-phase flow parameters. In the presented model the impact of saturation distribution is somehow incorporated in estimation of three-phase k_r by defining characteristic coefficient (A_{ij}). This parameter make the three-phase k_r model more flexible compared to the existing models (that are limited between two-phase k_r). The best choice for value of A_{ij} is to determine it from measured three-phase k_r in an optimization process as presented in Fig.9. However, in absence of measured three-phase k_r, the characteristic coefficient can be used as tuning factor in history matching of reservoir production and pressure.
4. The input two-phase kr data (used in three-phase models) should be selected from an appropriate displacement process (i.e. drainage, imbibition) which correspond to the three-phase saturation history.

Acknowledgment

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- A new mechanistic model is proposed to predict the relative permeability (or flow function) of three immiscible fluids (i.e. oil, water and gas) in the petroleum reservoirs.
- The model incorporate the impact of the fluid distribution and physical mechanisms of the flow in the relative permeability of fluids.
- The model is supported and validated against the experimentally measured three-phase relative permeability data.