Selection of Three-Phase Relative Permeability Model for Mixed-Wet Reservoirs

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Abstract

The most widely used three-phase relative permeability models are Stone1 and Baker. The mixed-wet condition is perhaps the most frequently encountered wetting condition worldwide. Two models for mixed-wet systems have been developed in recent times, Blunt's (2000), which is somewhat complex to use in simulators, and Jerauld's (1997) that is relatively easier to implement. The model incorporates the effect of interfacial tension (IFT) between phase pairs as well as the ability to model mixed wettability and incorporates IFT effects. In this paper Stone1 and Jerauld's models are compared.

We illustrate the differences in performance prediction between the two models in three-phase oil relative permeability (k_{ro}) for the same two-phase relative permeability data sets. We show how these formulations can be used in commercial simulators. Recovery prediction differences as well as the effect of gas miscibility on oil relative permeability to water (k_{row}) are shown. Results show that three-phase k_{ro} values, based on Jerauld's model, can be up to 2 times lower than those predicted by using Stone1 and consequently recovery might be overestimated by 21% at immiscible condition, while at 80% miscibility, the underestimation becomes only 0.75% if Stone1 model is used. Gas miscibility diminishes k_{row}, resulting in lower recovery. The recovery is overestimated by 13% at 80% miscibility, if the effect of miscibility is only accounted for oil-gas relative permeability. We show the importance of using an adequate three-phase model in mixed-wet system in addition to accounting for the effect of gas miscibility on oil-water relative permeability.

Introduction

Mixed wettability is possibly the most frequently encountered condition in reservoirs. However, the vast majority of experiments have been done for water-wet and oil-wet systems (Donaldson and Dean, 1966; Sahni et al., 1996; Maini et al., 1990; Oak et al., 1990; Oak, 1991). Relative permeability measurements in mixed-wet system are limited to few data sets. DiCarlo (2000) measured relative permeability in mixed-wet sand packs, while Jerauld (1997) did extensive studies on Prudhoe Bay cores. There have not been proper two- and three-phase relative permeability models for mixed-wet media for decades (Pejic and Maini, 2003) and still none of the commercial simulators properly incorporates mixed-wet relative permeability models to the best of our knowledge. Hustad (2002, 2009) present a fully coupled formulation for three-phase capillary and relative permeability, which also incorporates hysteresis and miscibility on both capillary pressure and relative permeability. The questions raised here are whether we need to use mixed-wet relative permeability models, and also how much error might arise from application of water-wet relative permeability models rather than mixed-wet ones.

Most of the new models have not been evaluated for mixed wet systems. Oliveria (2003) compared some models for water-wet systems and showed that Stone 1 matched the experimental data significantly better than Baker, Hustad, Delshad and Dicarlo models. Kjosavik (2002) introduced two-phase relative permeability for mixed-wet rock based on Corey-Burdine model; he did not extend his work to three-phase relative permeability. Blunt (2000) established a three-phase model based on saturation-weighted interpolation between the two-phase permeability curves. This model accounts for wettability, trapping and layer drainage. Blunt's model assumes the same amount of gas is trapped by water and oil, which is valid for water-wet rocks, thus requiring extensions of the model to other than water-wetness (Blunt, 2000). Also, the choice of oil saturation when layer drainage starts is arbitrary, i.e. a free matching parameter needs to be adjusted. Jerauld (1997) developed two- and three-phase relative permeability models. These are only models tied to experimental data that we are aware of. Unlike Blunt's model, Jerauld's model requires none of the extensions or matching parameters.

The second important issue that has not been addressed in earlier publications is the effect of miscibility on all pairs of relative permeability curves, and consequently recovery. There are two main models which incorporate interfacial tension (IFT) parameter between phases: Blunt's (2000) and Jerauld's (1997). Both models consider the effect of miscibility on all phase-pairs. For instance, when the injected gas is partially/completely miscible in oil, then the two-phase oil-gas relative permeability, k_{rog} and k_{rgo}, will be altered. However, since oil composition changes, oil-water relative permeability is subject to change. Thus, the legitimate question is how much error might arise if miscibility effects on the third phase are ignored.

It should be noticed that Todd-Longstaff model in black oil simulation cannot address the effect of miscibility on the third phase. Although compositional simulation can properly track fluid property changes (Christensen et al., 2000), it cannot produce the change in relative permeability. However, Hustad's model has been incorporated in commercial software, which enables it to consider the effect of composition on relative permeability as compositions changes. Hustad's model interpolates relative permeability between immiscible and perfect miscibility by using a normalized IFT. However, Blunt (2000) and Jerauld (1997) claimed their models can contemplate IFT alteration. Here, we did not employ Blunt's model due to free matching parameter and its complexity; instead we used Jerauld's model, as an extension to Stone 1, which is simpler for execution in numerical simulators.

We explore both questions, proper choice of three-phase relative permeability and gas miscibility effects on k_{row}, and find that both issues are important and require attention when dealing with mixed-wet and miscible systems. In the following section we will present step by step method to answer these two topics.

The objectives of this paper are twofold. First, we show the importance of using adequate three-phase relative permeability for mixed-wet systems and second, to present miscibility effects on third phase relative permeability. The paper is organized as follows. After the introduction, the model formulation is described in the theory and model section. In that section, the base algorithm is described along with the casting of Jerauld's model onto Stone1, as formulated in a commercial simulator. Results and discussions follow. Conclusions are provided at the end. An appendix provides additional outcomes from data analysis. A second appendix shows the conceptual model used in the simulation tests.

Theory and Method

Recasting Jerauld's model as Stone 1
Jerauld (1997) introduced two-and three-phase relative permeabilities for Prudhoe Bay, a mixed-wet sandstone formation. This model is unique because it includes a dependence of relative permeability on composition and consequently oil-gas interfacial tension in addition to the hysteresis in oil, gas and water. The model gas trapping data match very well the modified Land equation.

The oil phase relative permeability can be reduced to Stone1 if k_{roo} equals S_o. In fact, this is an extension of Stone1, which enables one to recast it as Stone1 to be implemented in commercial simulators. We show the k_{ro} difference between these two models as a function of gas and water saturations and then this difference is translated into recovery. The recovery difference for a conceptual sector model based on Stone1 rather than Jerauld's three-phase model is referred to as an error. To estimate this error, Jerauld's three-phase relative permeability model is recast as Stone 1-like to be implemented in simulators.

$$k_{rgg} \langle S_g \rangle = \frac{\left(1 + \theta c_{g2}\right) S_{gg}^{\theta c_{g1} + (1-\theta)}}{\left(1 + \theta c_{g2} S_{gg}^{\theta c_{g3}}\right)} \quad \ldots \ldots \ldots \ldots (1)$$

$$k_{rwh} = \frac{(1 + c_{wh5}) \left[\frac{S_w - S_{wrh}^*}{1 - S_{wrh}^*}\right]^{c_{wh4}}}{1 + c_{wh5} \left[\frac{S_w - S_{wrh}^*}{1 - S_{wrh}^{n*}}\right]^{c_{wh4}}} \quad \ldots \ldots \ldots \ldots (2)$$

$$k_{ro}{}^J = k_{roo} \frac{k_{rog} \langle 1 - S_g \rangle \times k_{rhw} \langle 1 - S_w \rangle}{k_{roo} \langle 1 - S_g \rangle \times k_{roo} \langle 1 - S_w \rangle} \quad \ldots \ldots \ldots \ldots (3)$$

while k_{ro} based on Stone1 model is

$$k_{ro}{}^{S1} = S_{oe} \frac{k_{rog} \langle 1 - S_g \rangle \times k_{row} \langle 1 - S_w \rangle}{k_{row}^{end} \times \left(1 - S_{ge}\right)\left(1 - S_{we}\right)} \quad \ldots \ldots \ldots \ldots (4)$$

Now if equations 1 and 4 are equated, we can calculate k_{row} for using in Stone1 model, in such a way that Stone1 reproduces Jerauld's model with an adapted k_{row}

$$k_{row}\langle 1 - S_w\rangle = \frac{k_{row}^{end} \times \left(1 - S_{ge}\right)\left(1 - S_{we}\right)}{S_{oe}} \times k_{roo}\langle S_o\rangle \frac{k_{rog}\langle 1 - S_g\rangle \times k_{rhw}\langle 1 - S_w\rangle}{k_{roo}\langle 1 - S_g\rangle \times k_{roo}\langle 1 - S_w\rangle} \dots\dots.(5)$$

$$k_{rog}\langle 1 - S_g\rangle = \left(\frac{1 - S_g - \theta S_{org}}{1 - \theta\,S_{org}}\right)^{\theta c_{og\,1} + (1-\theta)} \quad \dots\dots\dots\dots(6)$$

$$k_{roo}\langle S\rangle = \left(\frac{S - \theta S_{ot}}{1 - \theta S_{ot}}\right)^{\theta c_{o\,1} + (1-\theta)} \quad \dots\dots\dots\dots(7)$$

$$k_{rhw} = \frac{(1 - c_{hw\,2})S_1^{c_{hw\,4}}S_2^{c_{hw\,1}}}{1 + c_{hw\,2}S_1^{c_{hw\,6}}S_2^{c_{hw\,3}}} \quad \dots\dots\dots\dots(8)$$

The adapted k_{row}, calculated based on Eq. (5), is a function of S_g. However, we can only employ one k_{row} set, which means one single S_g for estimating the adapted k_{row} to mimic Jerauld's three phase model, in a Stone-like fashion. Therefore, we can implement Jerauld's model only in an incomplete way due to software limitation. We calculate the relative error of this methodology, based on the difference between adapted Stone 1's model, using Eq. (5), and Jerauld's relative permeability model. In other words, we compute the adapted k_{row}, Eq. (5), substitute it into Stone 1 model and then compare it with Jerauld's model results for the whole range of gas and water saturation. Figure 1 shows the flowchart for this methodology. The relative error between adapted Stone 1 and Jerauld models are plotted versus the single S_{gco} required for calculating k_{row}, as shown in Figure 2. The relative error between Stone 1 and Jerauld, when Eq. (5) is not utilized, is 22.4% for this particular system. However it reduces to less than 9% after adaptation.
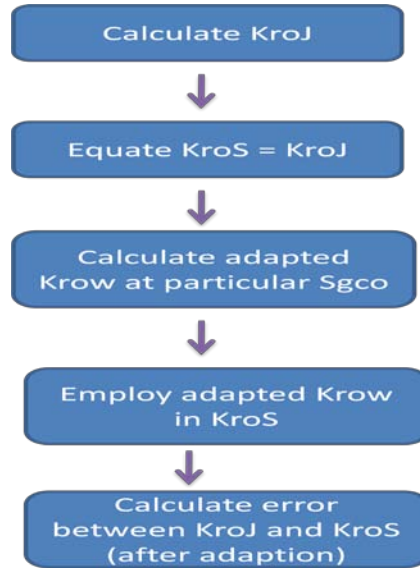

Figure 1. Algorithm of calculating adapted Stone 1 and relative error between adapted Stone 1 and Jerauld models.

One issue in calculating the relative error is how the difference between these two models in different regions of water and gas saturations impact recovery. In other words, this difference shall have a weighting factor for different regions. However, the relative error in Figure 2 is integrated for whole range of gas-water saturation without any weighting factor. Different regions will influence recovery differently. The regions are selected based on gas saturation since it does have much more effect on k_{ro} than water. These regions are low, mid and high gas saturations. Therefore, the effect of each region can be minimized by the proper choice of S_{gco}. The difference between these two models for different S_{gco}, different regions, is shown in Appendix 1.
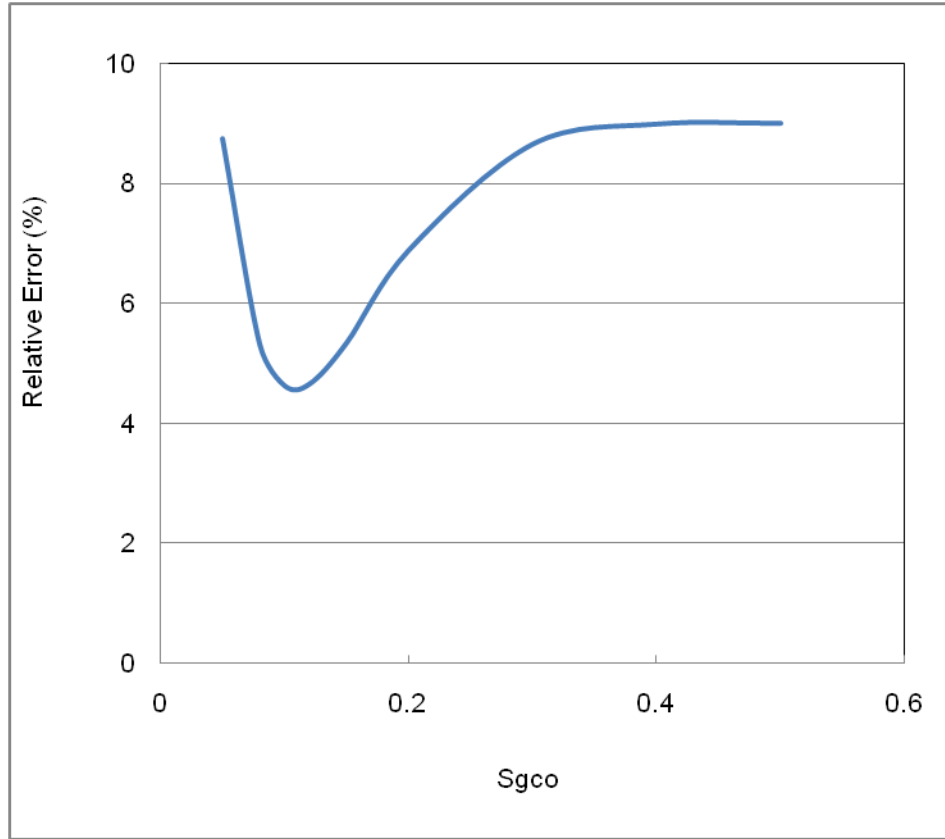
Figure 2. Relative error between adapted Stone 1 and Jerauld model with respect to S_{gco}.

Gas miscibility effect on k_{row}

Comparison of the gas and oil equations shows that they can be combined into a single, hydrocarbon hysteresis model with respect to miscibility to yield:

$$K_{rhw} = \frac{(1 + c_{hw2})S_1^{c_{hw4}} S_2^{c_{hw1}}}{1 + c_{hw2}S_1^{c_{hw6}} S_2^{c_{hw3}}} \quad \ldots \ldots \ldots (8)$$

where

$$S_1 = \frac{S_{hw}^{max} - S_{htw}(S_{hw}^{max})}{1 - S_{hrw}} \quad \ldots \ldots \ldots (9)$$

$$S_2 = \frac{1 - S_w - S_{htw}(S_{hw}^{max})}{S_{hw}^{max} - S_{htw}(S_{hw}^{max})} \quad \ldots \ldots \ldots (10)$$

and

$$S_{htw} = \frac{S_{hw}^{max}}{1 + \left(\frac{1}{S_{hrw}} - 1\right) \times (S_{hw}^{max})^{\frac{1}{1 - S_{hrw}}}} \quad \ldots \ldots \ldots (11)$$

The maximum hydrocarbon saturation is calculated from the following equation (see Jerauld (1997) for more details).

$$S_{hw}^{max} = \max\{1 - S_w, S_g^{max} + f_h(1 - S_w^{min} - S_g^{max})\} \ldots \ldots .. (12)$$

$$S_{hrw} = (1 - f_h)S_{gr} + S_{orw} \ldots \ldots \ldots \ldots \ldots (13)$$

$$c_{hw1} = (1 - f_h)c_{g1} + f_h c_{ow1} \ldots \ldots \ldots \ldots (14)$$

$$c_{hw2} = (1 - f_h)c_{g2} + f_h c_{ow2} \ldots \ldots \ldots \ldots (15)$$

$$c_{hw3} = (1 - f_h)c_{g1}\left(1 + \frac{1}{c_{g2}}\right) \ldots \ldots \ldots (16)$$

$$c_{hw4} = (1 - f_h)c_{g1} + f_h c_{ow4} \ldots \ldots \ldots \ldots (17)$$

$$c_{hw6} = (1 - f_h)c_{g1}\left(1 + \frac{1}{c_{g2}}\right) + f_h c_{ow6} \ldots \ldots \ldots .. (18)$$

The value of f_h is calculated based on Parachor-weighted molar density change as a measure of composition alteration. This parameter can be calculated compositionally. Ayirala and Rao1 (2006) offered a new mechanistic Parachor model to predict dynamic interfacial tension and miscibility in complex hydrocarbon system where traditional Parachor model fails to provide IFT applicable for mass transfer between phases. However we do not need this complex procedure since we already calculated IFT and we are interested in using pseudo-components. Here all components are lumped into one pseudo-component and then IFT and density of this pseudo-component are calculated based on Peng-Robinson equation of state. Parachor parameter is estimated by Macleod (1923) and Sudgen (1924) method, Eq. (19).

$$P = \frac{\sigma^{\frac{1}{4}}}{(\rho_m^l - \rho_m^v)} \dots\dots\dots (19)$$

F_h, normalized Parachor-weighted molar density, and miscibility are calculated and plotted versus each other, Figure 3.
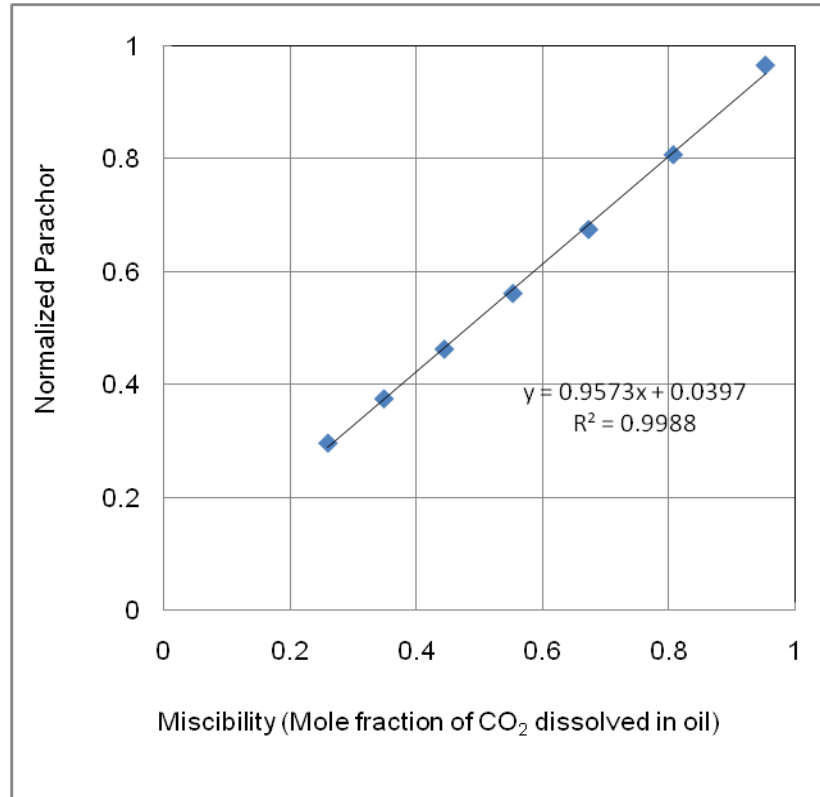

Figure 3. Normalized Parachor-weighted molar density versus miscibility factor of CO_2 in Oil.

S_{hrw} and k_{rhw} change with respect to how oil becomes gas-like. Therefore hydrocarbon-water relative permeability can be adjusted with respect to miscibility (Eq. (8)).

Results and discussion
We will cover three main aspects here. First, the relative permeability in Jerauld's model is compared with Stone 1 model. Then, the effect of miscibility is investigated on oil-water relative permeability.

Comparison of three phase relative permeability
 Several aspects of rock-fluid interactions in mixed-wet systems have been assessed. Results reveal that proper choice of three-phase relative permeability model is quite important: more than 21% error is found if an inadequate three-phase relative permeability model is used. Figure 4 shows the absolute difference in k_{ro} between two three-phase models using Jerauld and Stone1. There is a significant difference at S_{gr}, and as expected gas saturation has a more pronounced effect on k_{ro}. The oil three-phase relative permeability on these two models and adapted Stone1 are compared in Figure 5 for two miscibility factors. As expected, two models reach the same shape at higher miscible situation. The gas saturation is at residual (0.05). It can be concluded that difference in recovery becomes smaller at higher miscibility, as shown in Figure 6.
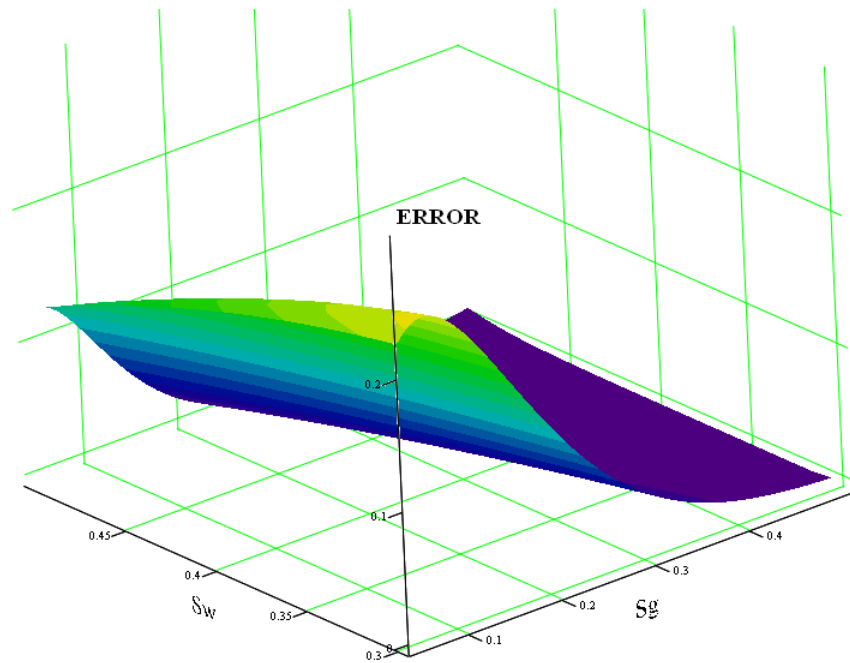
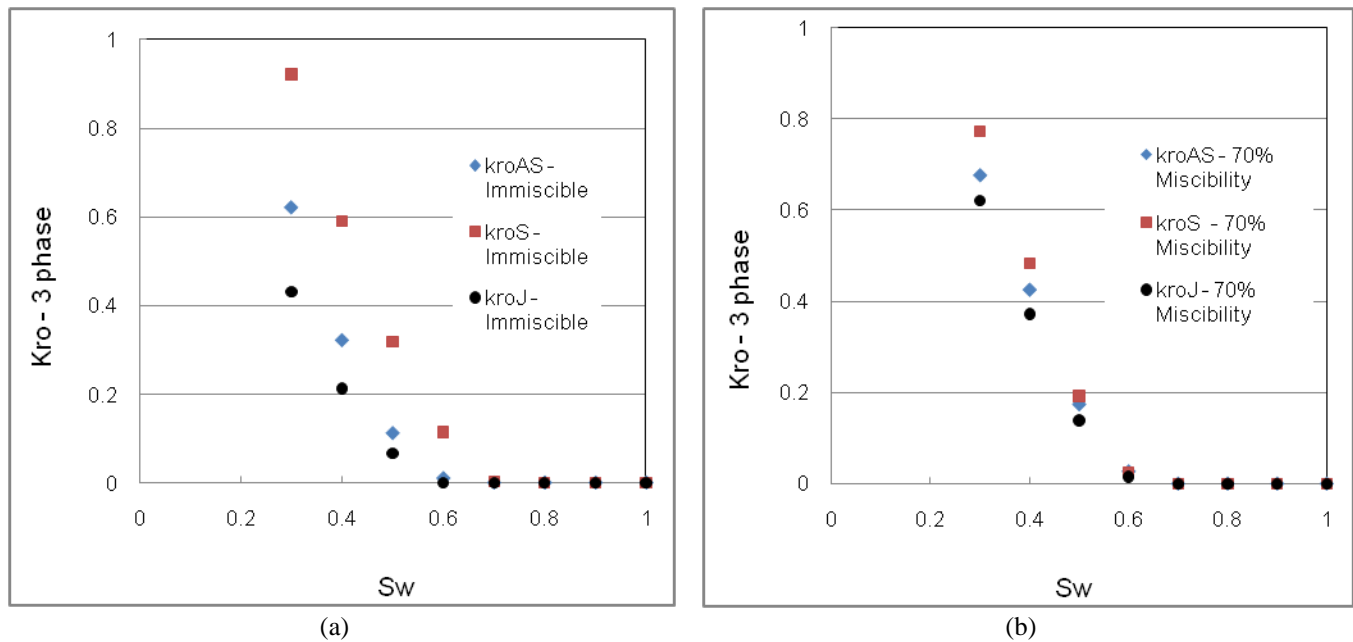Figure 4. Absolute oil relative permeability difference between Jerauld and Stone I models.

| (a) | (b) |

Figure 5. Comparison of k_{ro}-three phase between Jerauld, Stone 1 and adapted Stone 1 for immiscible (a) and 70% miscibility (b).

The difference between two three-phase relative permeability models might have a significant influence on recovery. We compared recovery in a sector model. We used a conceptual model (Appendix 2), where k_{ro} (three-phase model) is calculated using these two different models to show how Stone1 model overestimates recovery for wide range of miscibility conditions. The recovery is highly overestimated, being 21% at low miscibility while this difference becomes smaller at high miscibility, as shown in Figure 6.
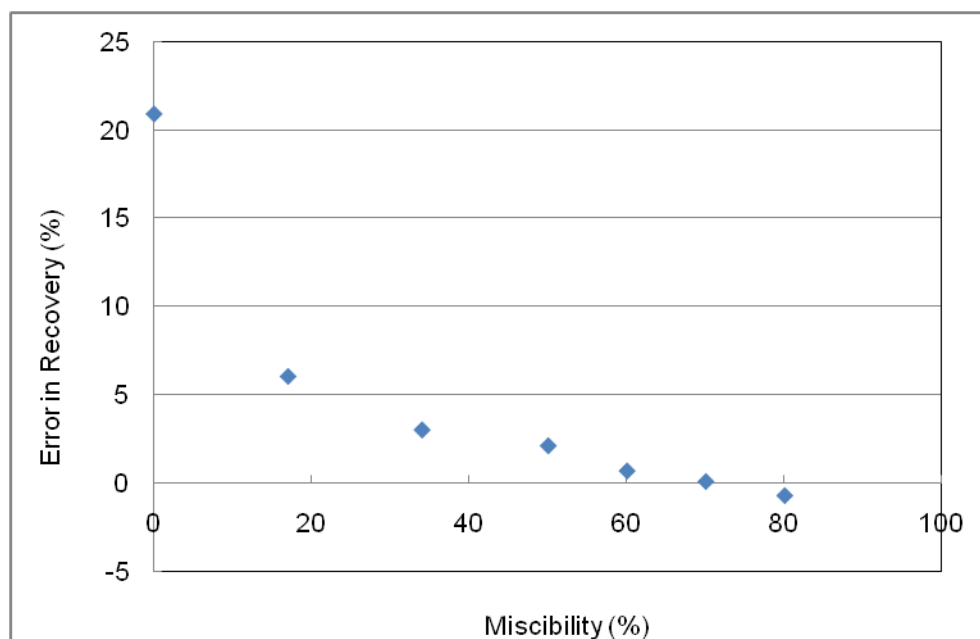
Figure 6. Comparison of Jerauld three-phase model with Stone1 for a wide range of miscibility.

Miscibility effect on oil-water relative permeability

Moreover, gas miscibility effects on k_{row}, which are not generally properly addressed in simulation, have appreciable effects on recovery. Gas miscibility changes fluid properties and relative permeability. Compositional simulation could properly track the fluid property change, but there is no straight forward solution for relative permeability alteration. Todd and Longstaff's miscible scheme, i.e. black oil approximation to compositional simulation, might address oil-gas relative permeability alteration based on a miscibility factor but it does not provide a way to deal with how oil-water relative permeability might change. Blunt's and Jerauld's three-phase relative permeability models could address this issue.

We employed Jerauld's model to consider the miscibility effects on all phase relative permeability pairs, k_{rog}, k_{rgo} and k_{row}. This model enables one to track third phase relative permeability alteration, k_{row}, which is not typically pondered due to lack of IFT parameterization in relative permeability models.

Although gas miscibility might lower oil viscosity, it could at the same time reduce the oil-water relative permeability to yield a sooner breakthrough and less recovery (Figure 7). Therefore, recovery might be overestimated if gas miscibility effects are only considered on oil viscosity and oil-gas relative permeability. Oliveira and Demond (2003) (Figure 3 in their article) compared Baker, Hustad, Delshad, DiCarlo, Parker, Brooks, Stone 1 and 2 models. They divided these models to two main groups; group one prediction is off by one order of magnitude and group two which their predicted data has the same order of magnitude as a measured data. The group two consists of Stone 1, Stone 2, Parker and Brooks.

The effect of miscibility on all phases can also be simulated by Hustad method (Hustad and Browning, 2009). Since this model is incorporated in a commercial simulator, then miscibility can be estimated at each grid block. Therefore, it does not require our assumption, i.e. a homogenous miscibility condition. However, the linear interpolation of relative permeability between immiscible and perfect miscibility based on normalized IFT, Hustad model, was not proven. In addition, ODD3P, Hustad's relative permeability model, has not been compared against experimental data to the best of our knowledge.
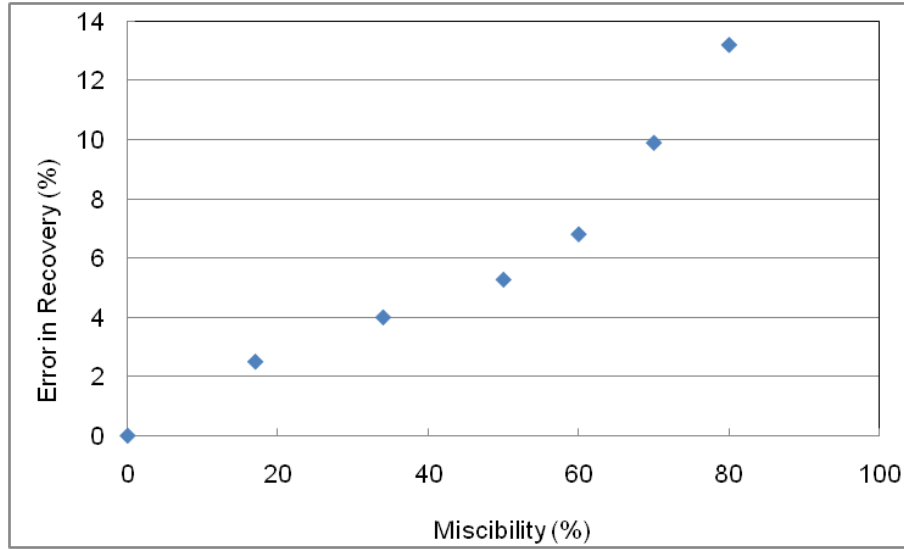
Figure 7. Error in recovery as a result of gas miscibility effect on k_{row}.

This study has some shortcomings. First, we cannot employ Jerauld's model fully by using the algorithm presented here, which causes at least 4% average relative error in relative permeability estimation. Second, Jerauld's model has not been compared with other mixed-wet relative permeability data sets. Third, miscibility was assumed to be the same for the whole system, along with the perfect mixing condition. In reality, miscibility is not homogenous and therefore various miscibility conditions exist at different location. In other words, we need compositional functionality of relative permeability in numerical simulators for all pairs.

However, the algorithm presented in this paper reduces relative error from 22.4% to the range of 4-9% as shown in Figure 2. This study brings the importance of using adequate three-phase relative permeability model to light. Therefore, if a mixed-wet reservoir encounters three-phase flow situations such as water flooding below bubble point and/ or water alternating as (WAG), the economical assessment would be optimistic if water-wet relative permeability model is used (see Figure 6). Also, Miscibility effects on the third phase can predict less recovery. Thus, miscible flooding, e.g. CO_2, might not be as promising as is predicted before.

Conclusions
We show that significant overestimation of recovery can be obtained if Stone1's model is employed rather than Jerauld's for mixed-wet systems. More than 21% errors might occur. Also, the change in oil-water relative permeability due to gas miscibility in oil yields substantial overestimation of recovery, up to 13%. The algorithm developed here allows one to implement a meaningful relative permeability model for three-phase flow in mixed systems through this formulation in simulators.

Acknowledgement

Nomenclature
c_{ijk} = k^{th} parameter in i-phase/j-phase relative permeability
f = function representing composition dependence
k_{rocw} = relative permeability to oil at initial water saturation
k_{ri} = relative permeability for I phase
k_{rij} = relative permeability of I phase with relation to j phase
P = parachor weighted molar density
S_i = saturation of i phase
S_{gc} = criticalgas saturation
S_{gco} = gas saturation used for calculation of adapted k_{row}
S_{gt} = trapped gas saturation
S_{irj} = maximum residual of phase i with relation to phase j
S_{ie} = effective saturation of phase i (see ref. Jerauld 1997)
S_w^{min} = minimum water saturation
θ = function describing Nc dependence
σ = interfacial tension

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Appendix 1

There are two main criteria for choosing S_{gco}, which are relative and maximum errors. The relative error between Stone 1 and Jerauld models is 22.4 %, before adaptation. This error can be reduced if we adapt Stone1 model to mixed-wet system by using Eq.(5). It is suspected that the maximum error redeems more numerical error on recovery. There is a trade off in choosing of S_{gco}, for instance, if we pick the low gas saturation region, then the maximum error is low while the relative error is not minimal. The relative error is 8.7% , Figure 2, at S_{gco} equals 0.05 (comparison of two models their selves) while the difference in recovery between a sector model using Stone 1 and Jerauld models are 21% Figure 6 (comparison of effect of two models on recovery). However, at S_{gco} equals 0.1, the relative error would be 4% less than the corresponding value at S_{gco} = 0.05, but the difference in recovery is 41%.

The difference in recovery becomes much more, 118% at S_{gco} = 0.22. Therefore, we speculate that the high error at low gas saturation, where k_{ro} is high and consequently its contribution to recovery is significant, shall be used as main criterion for S_{gco} selection. Therefore we select S_{gco} = 0.05 for our study. This selection redeems less difference between Jerauld and Stone 1 models, more optimistic results. In other words, we would counter more error if a higher S_{gco} is picked. Relative error before and after adaption is compared in Figure 8. Also, the absolute oil relative permeability difference between models for S_{gco} equals 0.1 and 0.22 is shown in Figure 9. It appears S_{gco} = 0.22 is not a proper choice.

(a)
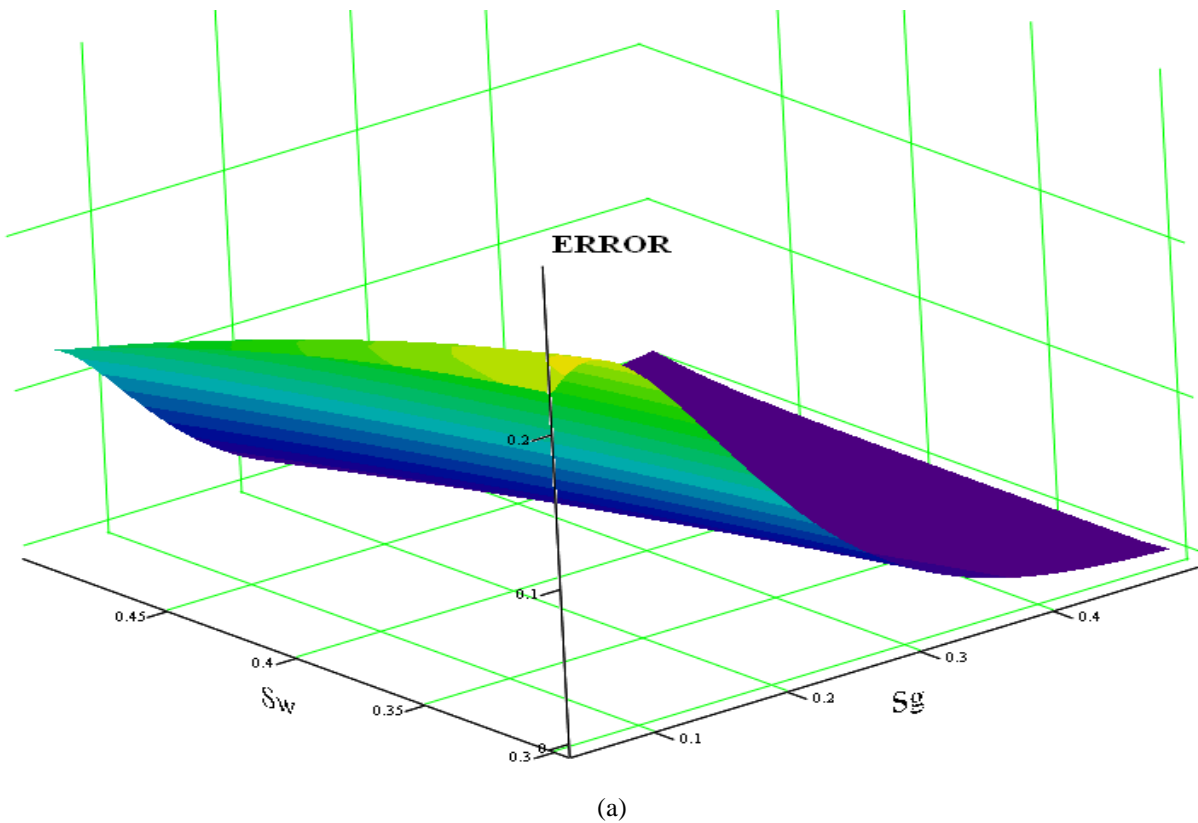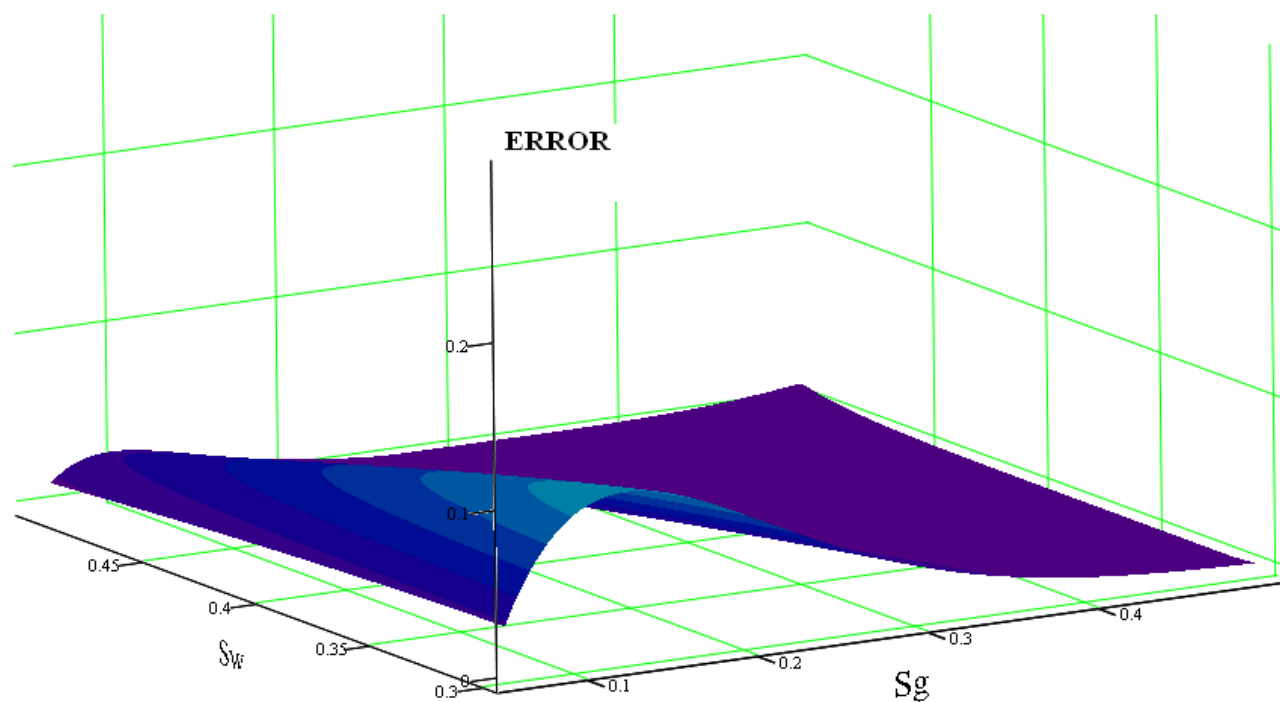
(b)

Figure 8. Comparison of absolute oil relative permeability difference between Jerauld and Stone I models before (a) and after (b) adaption.
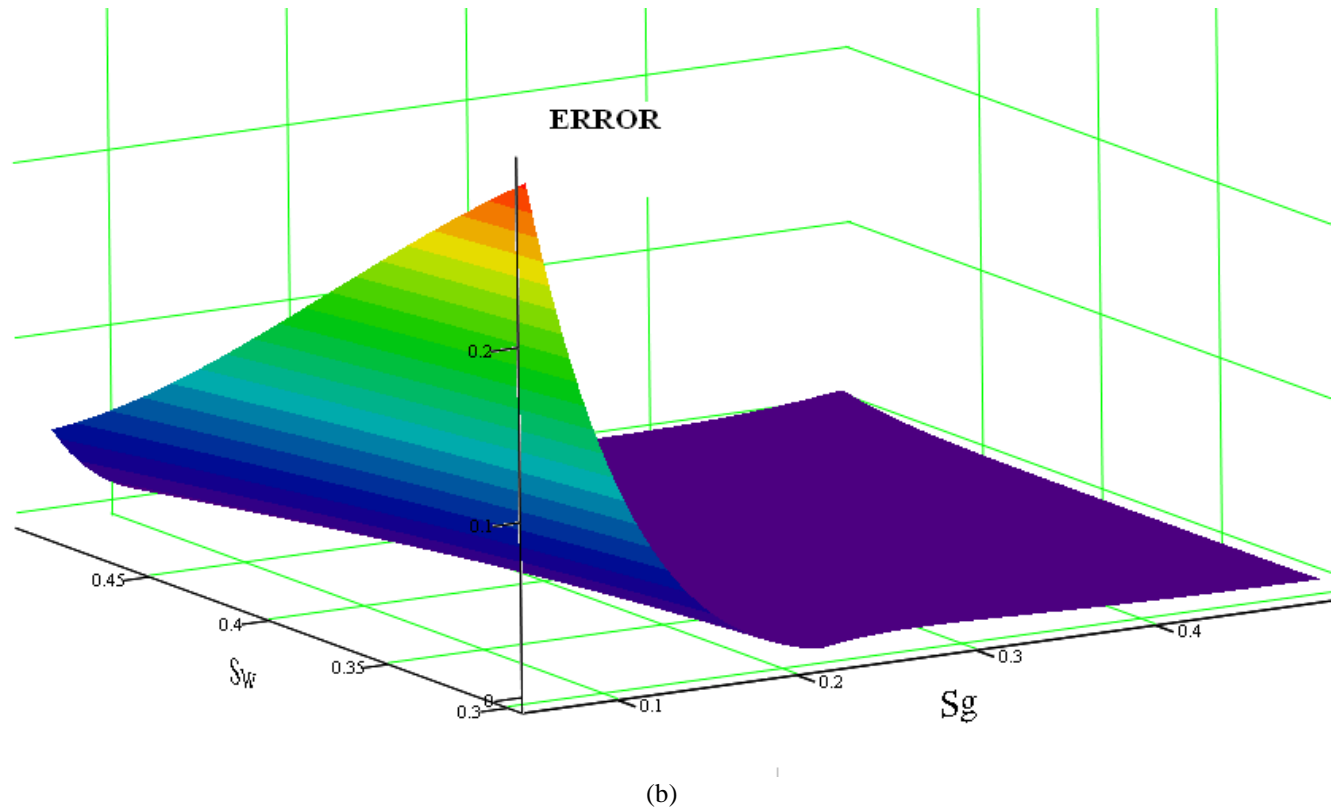

(a)

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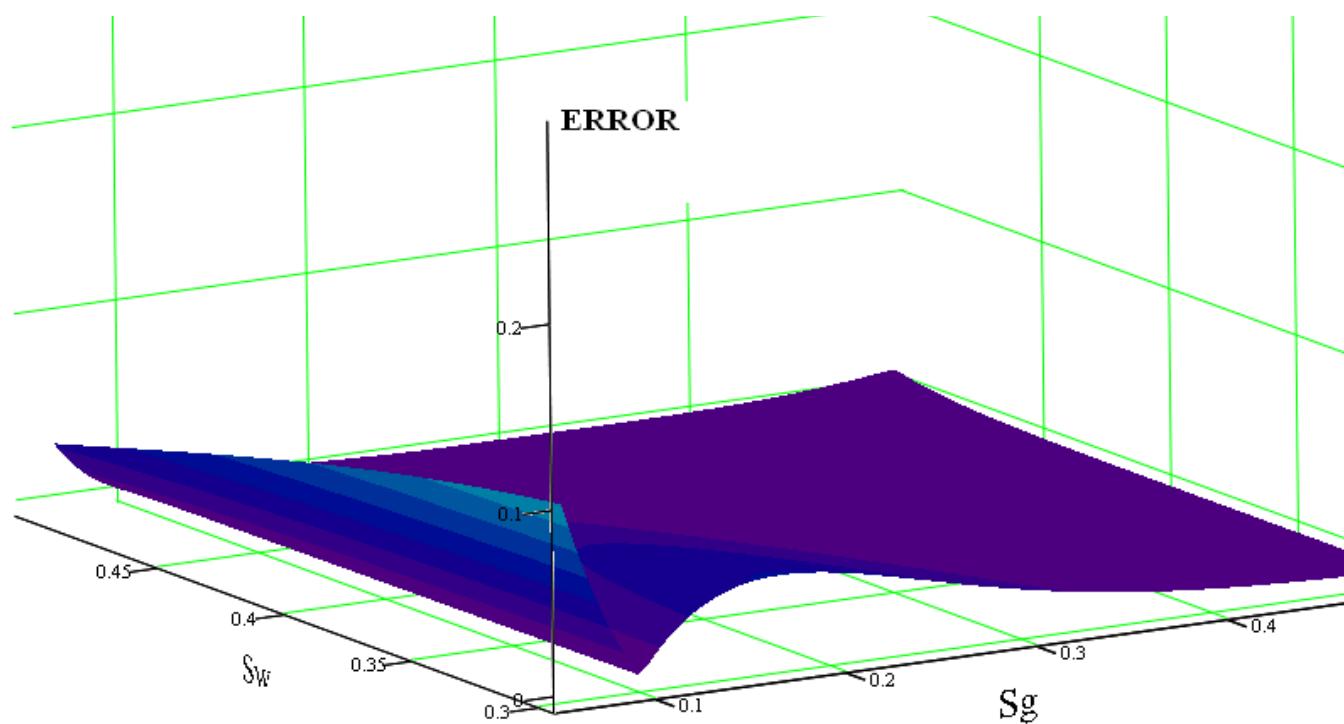
Figure 9. Comparison of absolute oil relative permeability difference between Jerauld and adapted Stone l for S_{gco} equals 0.1 (a) and 0.22 (b).

Appendix 2

The conceptual model used in the simulations is shown in Figure 10, containing 4 layers. The average model data are shown in Table 1.
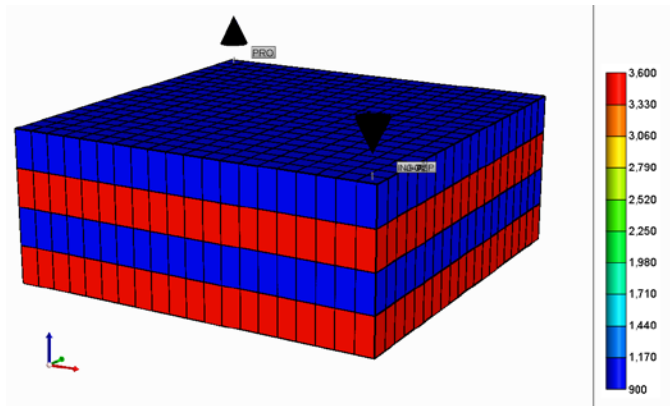

Figure 10. Reservoir conceptual 3D model.

Table 1. Static reservoir data

Parameter	value
Porosity	0.26
Average Horizontal Permeability (md)	2250
Average Vertical Permeability (md)	225
Dimensions	1000*1000*134
Formation pressure (PSI)	2000
Temperature (°F)	165