

# Effects of wettability and pore-level displacement on hydrocarbon trapping

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## Abstract

We use a three-dimensional mixed-wet random network model representing Berea sandstone to extend our previous work on relative permeability hysteresis during water-alternating-gas (WAG) injection cycles [Suicmez, VS, Piri, M, Blunt, MJ, 2007, Pore-scale simulation of water alternate gas injection, Transport Porous Med 66(3), 259–86]. We compute the trapped hydrocarbon saturation for tertiary water-flooding, which is water injection into different initial gas saturations,  $S_{gi}$ , established by secondary gas injection after primary drainage. Tertiary water-flooding is continued until all the gas and oil is trapped. We study four different wettability conditions: water-wet, weakly water-wet, weakly oil-wet and oil-wet. We demonstrate that the amounts of oil and gas that are trapped show surprising trends with wettability that cannot be captured using previously developed empirical trapping models. We show that the amount of oil that is trapped by water in the presence of gas increases as the medium becomes more oil-wet, which is opposite from that seen for two-phase flow. It is only through a careful analysis of displacement statistics and fluid configurations that these results can be explained. This illustrates the need to have detailed models of the displacement processes that represent the three-phase displacement physics as carefully as possible. Further work is needed to explore the full range of behavior as a function of wettability and displacement path. © 2007 Elsevier Ltd. All rights reserved.

**Keywords:** Network modeling; Three-phase flow; Fluid configurations; Trapping; Wettability; Relative permeability; Double displacements; Pore occupancy

## 1. Introduction

At present, the almost universal practice in the oil industry is to use empirical models to predict three-phase flow properties, such as capillary pressure and relative permeability, that are extrapolations from two-phase measurements [21,22,1]. However, the three-phase relative permeability is known to be a function of two saturations and the displacement path, indicating that a finite number of measurements is unlikely to reproduce the full range of behavior [1,5,25]. One simplifying hypothesis is to propose that the relative permeability is a unique function of the

flowing (non-trapped) fluid saturation [4,3]. Hence relative permeability could be predicted from a single displacement experiment if the trapped saturation were known.

Land [14] developed an empirical expression in the context of two-phase flow that relates trapped non-wetting phase saturation to the initial and maximum non-wetting phase saturations in the system. This model embodies the idea that the maximum non-wetting phase saturation determines the amount of trapping.

Using data from Prudhoe Bay sandstone core samples, Jerauld [9] suggested that pore structure may also play an important role in determining the trapped gas saturation. He showed that the trapped gas saturation decreases with increasing porosity for sandstones. He proposed that lower porosity samples have larger pore-throat aspect ratios which in turn results in more snap-

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off displacements disconnecting gas clusters. Jerauld [10] also suggested that the total hydrocarbon (oil and gas) trapped in a three-phase system would be up to 20% greater than the water-flood residual oil saturation during two-phase flow. He concluded that unless the system is strongly water-wet, the trapped gas and residual oil saturations should be approximately independent since they are not necessarily competing to occupy the same pores.

Blunt [3] developed a three-phase trapping model by extending [14] two-phase model to three-phase systems. He assumed that the total trapped hydrocarbon saturation in a strongly water-wet system can be estimated by using a similar approach to Land. According to this model, the total trapped hydrocarbon saturation in a three-phase system should be the same as the trapped non-wetting phase saturation in a two-phase flow.

Kralik et al. [13] studied a comprehensive set of experimental data obtained from an oil-wet sandstone reservoir. They suggested that gas trapping not only depends on its own saturation but also on wettability and the relative amounts of the other two phases. It was shown that in oil-wet reservoirs the trapped gas saturation can be significantly lower in the presence of water, since gas may become the intermediate-wet phase which inhibits water to gas snap-off displacements during water invasion. This explanation is similar to that for two-phase systems in which residual oil saturation is lower for intermediate-wet systems than water-wet systems [8].

At present, despite the work described above, there is no robust model to predict trapping in three-phase flow for a complete range of displacement paths and wettabilities. In this work, we apply pore-network modeling as a tool to estimate the trapped hydrocarbon saturation in Berea sandstone. We will compute the trapped oil and gas saturations separately and relate them to the initial gas saturation and wettability of the system for a particular saturation path (gas injection followed by water injection). The advantage of this approach is that situations outside the range of displacements studied experimentally can be explored, and, from an analysis of displacement processes and fluid configurations, the trends in behavior can be given a physical explanation. The properties of the Berea network, with analytical computations of the threshold displacement pressures and transport properties have already been discussed in the literature [17,7,19,23]. We are not going to present all these equations here in this paper; however two- and three-phase fluid configurations and the relevant displacement mechanisms do deserve a brief introduction.

## 2. Network modeling

The fluids used in this work are assumed to be Newtonian, incompressible, and immiscible. The displacements at the pore scale are assumed to be quasi-static and capillary dominated.

### 2.1. Generic fluid configurations

Pore and throat elements with circular cross-section can only contain one phase. However, for the vast majority of elements that are angular, one or more phases may reside in them simultaneously, as shown in Figs. 1 and 2 [5,7,3,19]. Depending on the capillary pressure, spreading coefficient, contact angle and corner half angle values, it is possible to accommodate fluids in the corners of the angular pore and throat elements with the different configurations shown. Multi-phase fluid occupancy in real pore spaces is complicated and with the development of better visualization techniques and further understanding of fluid and rock properties, it is possible that other configurations may be found.

In all our simulations, we assume the system is initially 100% saturated with water and strongly water-wet. Once non-wetting phase (oil) migrates into the system during primary drainage, it invades the center of the element and changes the wettability of the central portion of the pore/throat [12]. Depending on the magnitude of the new contact angles, each pore or throat can become water-wet, oil-wet or intermediate-wet. The new configuration of the phases in the pore or throat element is dependent on the wettability of the system and the geometry of the elements.

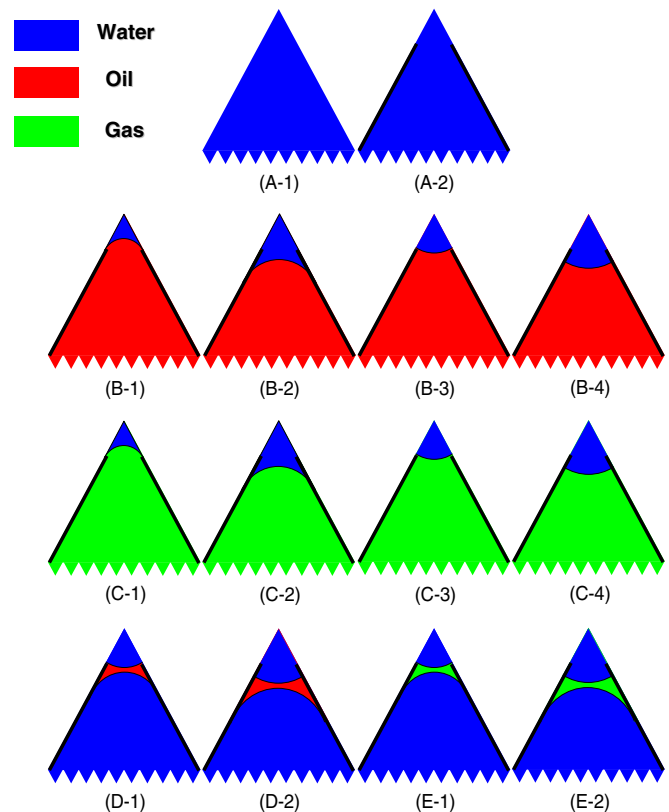


Fig. 1. One- and two-phase fluid configurations for a single corner. The bold solid line indicates the regions of the surface with altered wettability. From Piri and Blunt [19].

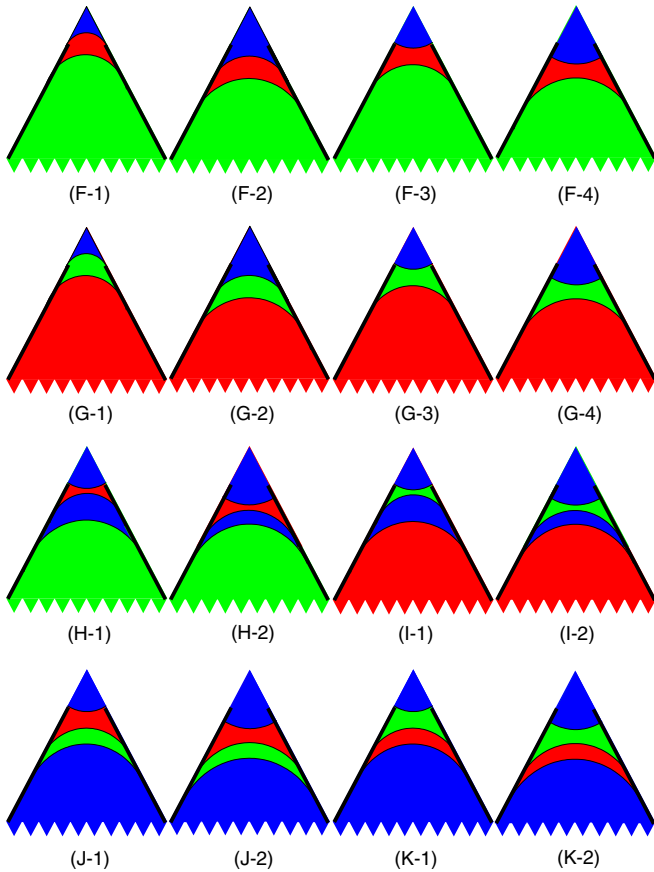


Fig. 2. Three-phase fluid configurations for a single corner. From Piri and Blunt [19].

We then simulate any sequence of water, oil and gas injection. At a known threshold capillary pressure, the configuration in an element will change. The sequence of configuration changes in the network defines the displacement. As an example, we can explain one way of reaching configuration F-1 (Fig. 2). As discussed above, we assume the system is initially saturated with water and the initial configuration is A-1 (Fig. 1). Then if oil invades a water-filled pore, it changes the wettability of the oil-occupied region and the new configuration will be B-1 (note that we assume the system remains water-wet in this case, as the oil/water contact angle,  $\theta_{ow}$ , is less than  $90^\circ$ ). Then, once we inject gas into the system, gas occupies the center of the pore leaving an oil layer between the water in the corner and the gas in the center – as long as pore geometry and gas oil contact angle,  $\theta_{go}$ , allow (this will be discussed in more detail in the next section) – and we end up with configuration F-1.

## 2.2. Displacement mechanisms and processes

A displacement might be either a single displacement (a continuous phase displaces another continuous phase) or a double displacement (a continuous phase displaces a trapped intermediate phase, which in turn displaces

another continuous phase). In this section we will only give a brief description of the principal processes we consider in our model. More details will be provided for cases where a thorough understanding is necessary to explain the results presented in the later sections.

We apply fixed pressures for connected phases across the whole network. We then increase the pressure of the phase that is being injected. A displacement event occurs when the pressure difference between the injected phase and that of the defending phase reaches a threshold value. For single displacements, this involves a change in configuration of any or all of the corners, or the center, of a single element. For double displacement, this involves separate configuration changes in two or more elements.

A displacement *process* indicates *what* is displaced, such as water displacing oil, or, for a double displacement, water displacing oil that displaces gas. A displacement *mechanism* indicates *how* the displacement occurs, that is how a change in local configuration occurs.

### 2.2.1. Single displacements

If a continuous phase is displaced by another continuous phase, then the displacement is called a single displacement.

A single displacement involves one of four sub-groups of local configuration change or mechanism: piston-like, pore-body filling, snap-off, and layer collapse and formation. Piston-like refers to the displacement of one phase by another through the center of a throat. Due to contact angle hysteresis, the threshold capillary pressure for piston-like displacement can be different for drainage and imbibition events. Pore-body filling refers to the displacement of one phase in the center of a pore by the displacing phase located in the centers of adjoining throats. For a drainage event, the threshold capillary pressure is given by similar expressions to piston-like advance. However the imbibition threshold capillary pressure for the displacement depends on the number of neighboring throats that hold the invading phase and are able to contribute to the displacement [15].

Snap-off corresponds to an imbibition mechanism where the non-wetting phase located at the center of the element is displaced by the wetting phase, which is located either in the corners or in layers. During water-flooding, spontaneous snap-off only occurs when  $\theta_{ow} + \alpha < \pi/2$ , where  $\alpha$  is the corner half angle and  $\theta_{ow}$  is the advancing oil/water contact angle. Snap-off is not favored over a piston-like or pore-body filling event when there is a neighboring element with the invading phase in the center that is able to carry out the displacement. For spontaneous snap-off the arc menisci in the corners (AM), which are the interfaces at the corners of a non-circular element, meet each other when they reach along the sides of the element.

The threshold capillary pressure for a spontaneous water–oil snap-off event in an  $n$ -sided regular pore or throat can be found by equating the half length of one side of the element to the meniscus–apex distance of the moving AM and is given as [7]

$$P_{\text{cow}} = \frac{\sigma_{\text{ow}}(\cos \theta_{\text{ow}} - \sin \theta_{\text{ow}} \tan \alpha)}{R} \quad (1)$$

where  $\sigma$  is the interfacial tension between the two fluids, and  $R$  is the inscribed radius of the element.  $P_c$  is capillary pressure – that is the pressure difference between phases. The threshold water pressure at which this event occurs is the oil pressure minus the capillary pressure,  $P_{\text{cow}}$ . Note that as the contact angle increases, snap-off becomes less favored. As a consequence, a significant number of snap-off displacements is normally only seen in strongly wetting systems.

Snap-off can also occur in gas–water systems. In this case we require  $\theta_{\text{gw}} + \alpha < \pi/2$  and the threshold capillary pressure is

$$P_{\text{cgw}} = \frac{\sigma_{\text{gw}}(\cos \theta_{\text{gw}} - \sin \theta_{\text{gw}} \tan \alpha)}{R} \quad (2)$$

Again note that snap-off is favored for low values of the gas/water contact angle.

The model used in this work considers layer collapse and formation as separate displacement events. Depending on the contact angles, capillary pressures, and corner half angles, layers may be formed through displacement from fluid residing in the center or the layers of neighboring elements. Once a layer forms, it is possible to collapse this layer with an increase in the pressure of the fluids residing on either side (corner or center). Sometimes the same phase (water) may be residing both in the corner and center of the element next to either a gas or an oil layer, in which case both the center and the corner contribute to the layer collapse event if the pressure of the water phase increases.

The presence and stability of oil layers are assessed using a geometric criterion [7]. If, after a displacement event, a layer can be drawn in the pore space at the prevailing capillary pressures then it is assumed to be present. This approach allows displaced intermediate-wet phase to remain as layer(s) sandwiched between the fluids in the corner and in the center of the element – if the pertinent contact angles, corner half angles and spreading condition of the system permit. However, recently it has been shown, using Helmholtz free energy balance principles, that these layers may not be formed after a direct displacement – it is energetically more favorable for the process to occur without a layer being left behind [26,18,28,29]. Furthermore, layers form and collapse at pressures that may be different from that derived geometrically: in brief, geometric stability is a necessary but not sufficient condition to determine the presence of a layer. It has been shown that using two-phase expressions for displacement capillary pressure combined with a geometric rule for layer stability in a three-phase flow context may lead to serious inconsistencies in the relation between pressures and pore occupancies for angular pore and throat elements. This may lead to incorrect estimations of the residual fluid saturations due to the inconsistent computation of the layer formation/collapse capillary pressure [28,29].

During both gas and water injection, oil layers may be formed and be present sandwiched between gas and water (see Figs. 1 and 2 – configurations D, F, H, J, K). Having these layers is extremely important especially in the low oil saturation region, since oil layers provide continuity of the oil phase and prevent trapping [3]. According to the geometrical criterion [7,19], oil layers may be formed during gas injection (Configuration F, Fig. 2), if

$$\theta_{\text{go}} + \alpha < \frac{\pi}{2} \quad (3)$$

Since the layer is surrounded by two different fluids, a change in the pressure of either fluid can result in a layer collapse event. Depending on the magnitude of the two contact angles ( $\theta_{\text{go}}$  and  $\theta_{\text{ow}}$ ), two different collapse scenarios are possible: if the gas/oil contact angle is larger than oil/water contact angle, then the layer is stable until the three-phase contact points meet each other (Fig. 3a, where phase  $i$  is gas,  $j$  is oil and  $k$  is water); instead if the oil–water contact angle is larger, then the layer is stable until two AM at a corner of a non-circular element meet each other at the center (Fig. 3b). We can use the same arguments to determine the possible existence of gas layers in the pore space by substituting  $\pi - \theta_{\text{gw}}$  for  $\theta_{\text{go}}$ : in this case gas layers are only seen if the gas/water contact angle is much greater than  $\pi/2$ .

Imagine a case where water is injected to displace gas and oil. We assume that the gas/oil interface was established during gas injection, so the gas/oil contact angle  $\theta_{\text{go}}$  is its receding value (the contact angle for gas displacing oil that may be different from the advancing angle for oil displacing gas due to contact angle hysteresis). We keep the gas/oil capillary pressure fixed and increase the water pressure (that is, decrease the oil/water and gas/water capillary pressures). The water in the corner swells until the oil/water interface contacts the gas/oil interface. If this occurs by movement of the oil/water/solid contact line towards the center of the element, then the prevailing oil/water contact angle  $\theta_{\text{ow}}$  is its advancing value (water displacing oil). We compute the threshold oil/water capillary pressure as follows [7]:

$$P_{\text{cow}} = \frac{\sigma_{\text{ow}} P_{\text{cgo}}}{\sigma_{\text{go}} R_c} \quad (4)$$

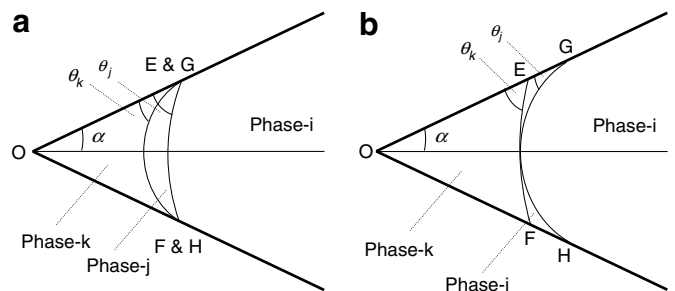


Fig. 3. A layer collapse event takes place once the fluids in the corner and the center touch each other [18]. (a)  $\theta_k < \theta_j$  and (b)  $\theta_k > \theta_j$ .

For  $\theta_{ow} > \theta_{go}$  the threshold ratio of curvatures is given by

$$R_c = \frac{\sin \alpha - \cos \theta_{go}}{\sin \alpha - \cos \theta_{ow}} \quad (5)$$

while for  $\theta_{ow} < \theta_{go}$ ,

$$R_c = \frac{\cos(\theta_{go} + \alpha)}{\cos(\theta_{ow} + \alpha)} \quad (6)$$

The other scenario for oil layer collapse event would be through the gas/oil interface moving towards to oil/water interface. The capillary pressure for this event can be calculated by reordering Eq. (4) [7]

$$P_{cgo} = \frac{\sigma_{go} R_c P_{cow}}{\sigma_{ow}} \quad (7)$$

There is, however, an exception to the above mentioned analysis. When water is injected into the system, the oil/water interface may hinge to reach the advancing oil/water contact angle. The interface may touch the gas/oil interface before or after reaching its advancing contact angle. For the latter case two scenarios are possible. If the interface reaches the advancing oil/water contact angle at a positive oil/water capillary pressure, then the threshold capillary pressure associated with the oil layer collapse event (due to water injection) is given by Eq. (4). But if the interface reaches the advancing value at a negative capillary pressure, without reaching the gas/oil interface, then the oil/water interface is considered “unstable” and there is no need for further reduction in oil/water capillary pressure to force the interface to move towards the gas/oil interface. Since it is unstable, it will move instantaneously and collapse the oil layer. We consider the threshold oil/water capillary pressure of this special oil layer collapse event to be the same as the capillary pressure at which the oil/water interface reached the advancing oil/water contact angle.

When we consider which event is favored, we need to consider the relative magnitude of different displacement pressures. For piston-like oil–water advance, the threshold capillary pressure is approximately given by

$$P_{cow} = 2\sigma_{ow} \frac{\cos \theta_{ow}}{R} \quad (8)$$

where  $R$  is the inscribed radius of the element. As we increase the oil/water contact angle, the threshold capillary pressure for all displacements decreases: all the displacements occur at a higher water pressure. This makes intuitive sense, since the medium has a lowered affinity to water. However, relative to piston-like advance, snap-off and layer collapse become relatively less favored and so occur less frequently.

For three-phase flow – as we discuss below – an assessment of which type of displacement is favored is more subtle. Table 1 shows the contact angles used in our simulations. The Bartell–Osterhof equation [2] constrains the gas/water contact angle once the oil/water and gas/oil contact angles are known. We will consider an oil spreading system where the gas/oil contact angle is zero. In this

Table 1  
Contact angles used to represent different wettability conditions

	$\theta_{ow}$	$\theta_{go}$	$\theta_{gw}$
Water-wet	30–50	0	25–42
Weakly water-wet	60–90	0	50–73
Weakly oil-wet	100–150	0	80–110
Oil-wet	150–180	0	110–116

The angles shown in the table are the advancing values. Receding values of  $\theta_{ow}$  and  $\theta_{gw}$  are 20° lower than the advancing ones. During primary drainage  $\theta_{ow}$  is assumed to be zero. Note that the gas/water contact angle,  $\theta_{gw}$  is computed by using [2] constraint.

case, the gas/water contact angle increases as the system becomes more oil-wet (an increasing oil/water contact angle). However, even for the most oil-wet conditions, the gas/water contact angle is only slightly greater than 90°. This implies that when water is strongly non-wetting to oil, it is only slightly non-wetting to gas. Now consider water injection into gas and oil. For water-wet systems (small oil/water contact angles) water is strongly wetting to both gas and oil and so will displace both phases. For oil-wet systems, water is non-wetting to both oil and gas and so requires higher displacement pressures. However, water preferentially displaces gas, since it is only weakly non-wetting to this phase and consequently has a lower entry pressure (the capillary pressure is close to zero in Eq. (8), substituting  $\theta_{gw}$  for  $\theta_{ow}$ , as opposed to large and negative for water displacing oil).

### 2.2.2. Double displacements

In two-phase quasi-static network models, a fluid phase is able to move and contribute to displacement events only if it is connected to the inlet or outlet. In three-phase flow, however, the displacement of trapped clusters is vital for predicting recovery: for instance oil that is trapped during water-flooding becomes reconnected by gas through the pore-scale migration and coalescence of oil clusters. Our model only considers double displacement where a continuous phase displaces a trapped phase that displaces another continuous phase. However, in principle, there may be an arbitrarily long intermediate chain of disconnected clusters displacing other disconnected clusters before displacement of a continuous phase [25,27]. There are six possible double displacements [5] out of which gas–oil–water (gas displacing trapped oil that displaces water), water–oil–gas (water displacing trapped oil that displaces gas) and water–gas–oil (water displaces trapped gas that displaces oil) displacements were included in our model. Since we do not consider oil injection here and water is almost always continuous (see Figs. 1 and 2 – [19]), the three other double displacement mechanisms are ignored.

When a double displacement is carried out, the displacement can be considered as two single displacements. The first one is a continuous phase displacing a trapped phase, and the second one is displaced trapped phase displacing another continuous phase. In our model, a phase cluster

connected to either inlet or outlet will be considered as continuous and will have exactly the same phase pressure as another phase cluster connected to either inlet or outlet. For instance, if we have a gas cluster connected to the inlet and another gas cluster connected to the outlet, we do not treat them as two different clusters. They are considered as members of one big continuous gas cluster and have exactly the same phase pressure. However, if a phase is not connected to either inlet or outlet then it is considered as trapped and may move only through double displacement.

To perform the double displacement, we first increase the trapped phase *absolute* pressure to the threshold absolute pressure of the second single displacement (trapped phase displacing the continuous phase). Then, by adding this difference to the threshold pressure of the first single displacement (continuous phase displacing the trapped phase at its initial pressure), we can calculate the threshold pressure for the double displacement event

$$P_{DDk}^{\text{threshold}} = P_{\text{first}}^{\text{threshold}} + P_{\text{second}}^{\text{threshold}} - P_{\text{trapped}} \quad (9)$$

where  $P$  is the absolute pressure, DD stands for double displacement, *first* is the displacement of trapped phase by a continuous phase, and *second* is the displacement of the continuous phase by the displaced trapped phase.

If a trapped cluster of some phase becomes connected to either the inlet or outlet as a result of double displacement, then we re-set the pressure of the continuous clusters of that phase to the pressure of this previously trapped cluster. This pressure of the cluster is set by the last double displacement event it was involved in: it is the pressure of the continuous displacing or displaced phase plus the capillary pressure for the single displacement in the double displacement sequence. For instance, consider gas displacing oil by double drainage. The oil pressure in the trapped cluster is equal to the gas pressure minus the gas–oil capillary pressure for the gas–oil displacement event. This will be the same as the water pressure plus the oil–water capillary pressure for the oil–water displacement. Phase pressures may change significantly due to double displacement: for instance, during water injection into a system saturated with both oil and gas, the continuous oil pressure may increase as double displacement connects hitherto trapped clusters by oil displacing gas through the neighboring pore/throat elements [23].

### 3. Results and discussion

The major advantage of network modeling is that once validated against experimental data, we can predict flow and transport properties for any given wettability and sequence of saturation changes. This model has been used to predict relative permeabilities during gas injection [20] and water-alternating-gas (WAG) flooding [23]. We will extend this work as a first step towards predicting three-phase relative permeabilities for any displacement path

with an emphasis on how much oil and gas is trapped for different initial gas saturation and wettability conditions. The contact angles used to represent water-wet, weakly water-wet, weakly oil-wet and strongly oil-wet systems are shown in Table 1. We conduct four sets of simulations with different initial gas saturations ( $S_{gi}$ ) for each wettability condition. We use same interfacial tensions (oil spreading system) used during our previous work ([23] –  $\sigma_{ow} = 48$  mN/m,  $\sigma_{go} = 19$  mN/m,  $\sigma_{gw} = 67$  mN/m) to predict Oak's experiments [16].

Initially the network is fully water saturated. Then oil is injected with an oil/water contact angle of zero until every pore and throat is oil-filled. At this stage the water saturation in the corners of the pore space and clays is 22%. We then assign contact angles as shown in Table 1. Gas is injected to an initial saturation between 30% and 60% with no water displacement; the saturation of oil is between 48% and 18%. Finally water is injected until both the oil and gas are trapped.

Fig. 4 shows the trapped gas saturation as a result of tertiary water injection into systems of varying initial gas saturation and wettability. Fig. 5 shows the trapped oil saturation, while Tables 2–7 give the displacement statistics.

Fig. 6 shows the oil–water capillary pressure during tertiary water-flooding. As we would expect, the capillary pressure decreases as the medium becomes more oil-wet and is negative for weakly and strongly oil-wet media.

Before we comment on the trends in oil and gas trapping with initial saturation and wettability, we will first study the displacement statistics, Tables 2–7.

Tables 2 and 3 show the statistics for gas displacement. One may expect to see a considerably smaller trapped gas saturation in the oil-wet system since gas layers may form between water in the corners and water in the center of a

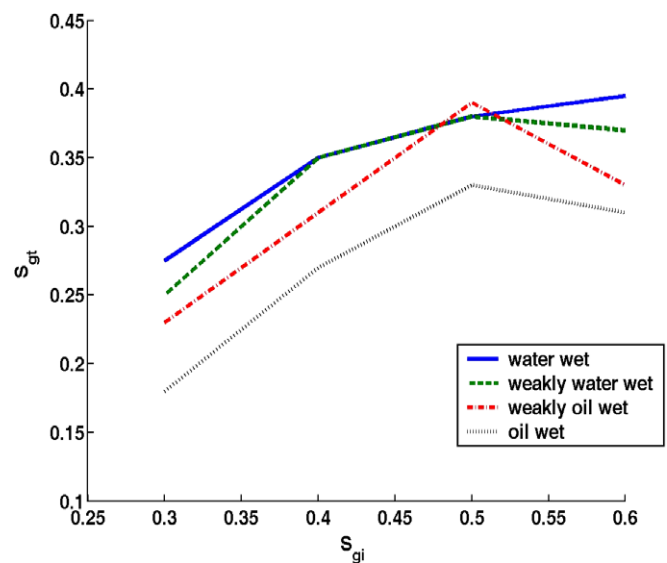


Fig. 4. Comparison of trapped gas saturation as a function of initial gas saturation.

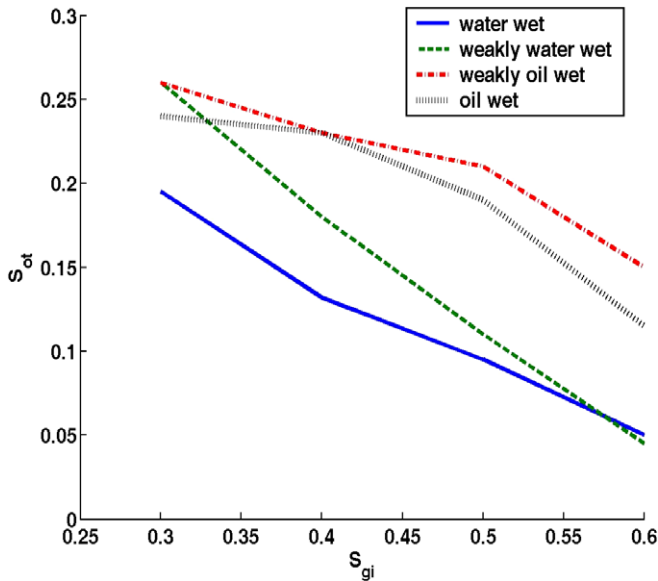


Fig. 5. Trapped oil saturation after tertiary water-flooding as a function of initial gas saturation.

Table 2

Number of gas displacement mechanisms (including water–gas direct and water–oil–gas double displacements) during tertiary water-flooding into initial gas saturations of 50% and 60% in a weakly oil-wet medium

Weakly oil-wet (%)	Piston-like	Snap-off	Layer collapse
$S_{gi} = 50$	2612	553	108
$S_{gi} = 60$	4690	668	16

Note that piston-like displacement includes both piston-like throat and pore-body filling events. In this and Table 3, layer collapse refers to the collapse of gas layers. Snap-off refers to the displacement of gas by water.

Table 3

Number of gas displacement mechanisms during tertiary water-flooding into initial gas saturations of 50% and 60% in an oil-wet medium

Oil-wet (%)	Piston-like	Snap-off	Layer collapse
$S_{gi} = 50$	4272	0	0
$S_{gi} = 60$	6833	0	0

Note that piston-like displacement includes both piston-like throat and pore-body filling events

Table 4

Percentage of oil displacement mechanisms (including water–oil direct and water–gas–oil double displacements) during tertiary water-flooding into an initial gas saturation of 40% for different wettability conditions

$S_{gi} = 40\%$	Piston-like	Snap-off	Layer collapse
Water-wet	44.2	15.1	40.7
Weakly water-wet	36.0	10.7	53.3
Weakly oil-wet	12.7	0	87.3
Oil-wet	11.6	0	88.4

Note that piston-like displacement includes both piston-like throat and pore-body filling events. In this and Table 5, layer collapse refers to the collapse of oil layers.

Table 5

Percentage of oil displacement mechanisms during tertiary water-flooding into an initial gas saturation of 50%

$S_{gi} = 50\%$	Piston-like	Snap-off	Layer collapse
Water-wet	43.5	14.5	42.0
Weakly water-wet	36.4	10.3	53.4
Weakly oil-wet	5.4	0	94.6
Oil-wet	5.4	0	94.6

Table 6

Number of different types of displacement process for tertiary water-flooding into an initial gas saturation of 40%

$S_{gi} = 40\%$	Number of displacements	Water–oil–gas	Water–gas–oil
Water-wet	37,518	232	2031
Weakly water-wet	35,109	332	12,339
Weakly oil-wet	35,746	166	27,675
Oil-wet	33,204	0	28,853

Note that the number of displacements include the total number of water–oil, and water–gas single displacements and water–oil–gas, water–gas–oil double displacements.

Table 7

Number of different types of displacement process for tertiary water-flooding into an initial gas saturation of 50%

$S_{gi} = 50\%$	Number of displacements	Water–oil–gas	Water–gas–oil
Water-wet	34,326	7	2865
Weakly water-wet	35,315	19	11,092
Weakly oil-wet	38,204	166	31,693
Oil-wet	37,006	0	32,688

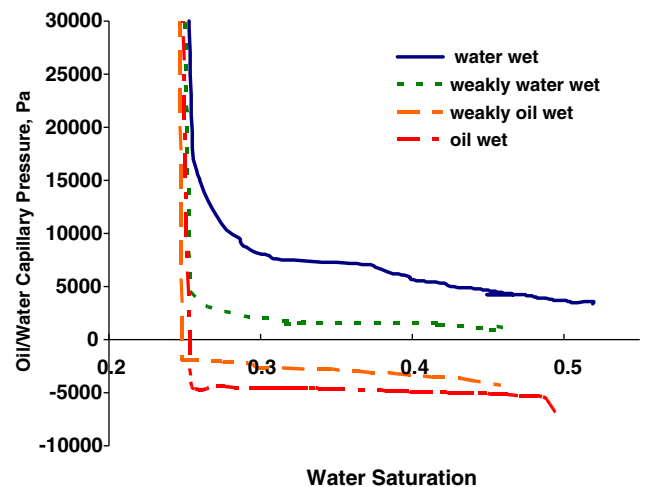


Fig. 6. Comparison of oil/water capillary pressure values obtained during tertiary water-flooding into an initial gas saturation of 40% for different wettability conditions.

given element (Configuration E, Fig. 1) that may increase the gas phase connectivity. However, the gas/water contact angle in the oil-wet system is not high enough to warrant

the formation of such layers in most cases – see Table 1. As a result, layer collapse is a rare event, since there are few gas layers. The trapped gas saturation is still lower for oil-wet media, Fig. 4, but the reason for that is explained below.

As expected, there is no snap-off involving water for the strongly oil-wet systems (Tables 3–5).

We observe that most of the displacement processes for the two oil-wet cases are water–gas–oil double displacement (Tables 6 and 7) with oil layer collapse being the most common mechanism (Tables 4 and 5). At the end of the secondary gas injection process (prior to water-flooding), gas always resides in the center of pores and throats (configuration F, Fig. 2) and oil layers inhibit the direct contact of water and gas clusters. Therefore, the only gas displacement mechanisms available initially are piston-like or pore-body filling events where water displaces gas and oil from the centers of elements, and oil layer collapse events caused by an increase in water or gas pressure. As discussed above, water preferentially invades gas rather than oil. While the gas phase is initially well connected, a few direct displacements by water trap much of the gas. For these trapped clusters the only way that they can be displaced by water is through double displacement, where water displaces gas that displaces oil. Gas is pushed from the centers of the larger pores into smaller elements, since water is non-wetting to gas and preferentially occupies the largest pores and throats. As water is injected, its pressure increases; similarly the gas phase pressure in trapped clusters also rises, as gas displaces oil from smaller elements. The result is a squeeze on oil layers – the phase pressures on both sides increase, precipitating a series of layer collapse events. However, it is the increases in gas pressure that is the more significant and leads to the gas/oil interface moving and collapsing the layer; as shown in Fig. 6, the oil/water capillary pressures remain relatively low and so the increase in water pressure alone does not account for this behavior. Hence, a double displacement is accompanied by a cascade of layer collapse, which becomes the dominant displacement mechanism. Once oil layers collapse, there is direct contact between gas and water, allowing snap-off; however, this mechanism is only seen for water-wet systems. Oil may also be displaced by snap-off (in water-wet media) or piston-like advance. The collapse of oil layers leads to oil trapping, since the oil is no longer continuous. The double displacement of trapped gas leads to rearrangement and reconnection of gas clusters. In oil-wet media, where the gas is forced into smaller elements, the amount of gas that is trapped will be relatively low, compared to water-wet systems where the gas remains in the larger pores.

This discussion leads to two conclusions: for oil-wet media, the cascade of oil layer collapse should lead to more oil trapping than water-wet systems (Fig. 5), while there is expected to be less gas trapping because gas is forced into smaller elements by double displacement (Fig. 4).

Now we will discuss the trends in trapping with initial gas saturation and wettability in detail. For low to interme-

diante values of the initial gas saturation, Fig. 4 shows an increase in trapped gas saturation with an increase in initial gas saturation. This is consistent with our expectation: the larger the amount of initial gas (prior to tertiary water-flooding), the greater is the size and number of gas clusters that may get bypassed, and eventually trapped through water-to-oil and water-to-gas piston-like displacements, as well as water-to-gas snap-off after oil layer collapse events.

The trapped gas saturation for cases with high initial gas saturation, however, does not follow the trend discussed above. The trapped gas saturation exhibits, except for the water-wet system (where the amount of trapping is controlled by snap-off), a reduction with an increase in the initial gas saturation. The displacement statistics suggest a similar finding. Tables 2 and 3 confirm that there are more water-to-gas displacements for oil-wet cases with higher  $S_{gi}$ , which results in less gas trapping. At lower  $S_{gi}$ , there is a significant amount of oil in the system. This oil is also displaced by water. When this happens, there is a water-filled element from which piston-like displacement of gas may be initiated. This means that gas clusters are displaced from many sites, making trapping due to bypassing relatively common. However, with little initial oil, displacement is initiated from the inlet or outlet of the network, with a connected advance and less trapping.

Fig. 4 also exhibits an interesting trend with wettability. The trapped gas saturation reduces with an increase in oil-wetness. For water-wet media, snap-off of gas by water is the dominant trapping mechanism, allowing large amounts of gas to be trapped. The gas is trapped in the largest pores that occupy a significant volume. In oil-wet systems, there is no snap-off and the gas is only trapped through piston-like displacement. Moreover, as discussed above, since water is the most non-wetting phase (see Table 1) it displaces gas from the larger pores, leaving it trapped in smaller elements. This observation is consistent with the results of Kralik et al. [13] in oil-wet media mentioned previously: the amount of gas that is trapped by water can be low in a three-phase system.

Fig. 5 shows the amount of oil that is trapped. The decrease in the residual oil saturation with an increase in the initial gas saturation has already been discussed in the literature [6,11]. At higher initial gas saturation there is simply less oil present in the network initially to be trapped.

The amount of oil that is trapped shows a remarkable trend with wettability. The water-wet case gives the least trapping. This is counter-intuitive and different from two-phase oil–water flows, where, due to snap-off, there is most trapping for water-wet media and least for an oil-wet medium, due to the connectivity of oil layers [24]. The amount of oil trapping is controlled by two factors: (1) how much oil is trapped by direct displacement of oil by water in elements containing no gas and (2) the stability of oil layers. In oil-wet systems oil layers are believed to be more stable. As the oil–water contact angle increases, as discussed



before, layer collapse becomes less favored compared to piston-like advance and we would expect to observe fewer layer collapse events. However, we actually find more oil layer collapse for oil-wet cases, as shown in Tables 4 and 5.

Our analysis of displacement statistics explains this behavior: for oil-wet systems, double displacement causes a cascade of oil layer collapse that in turn reduces the connectivity of the oil phase. As a consequence, more oil is trapped in these cases.

To recap: for oil-wet systems we observe a significant number of oil layer collapse events and more trapping than for a water-wet medium. This is an unexpected observation that can only be explained through a careful analysis of three-phase displacement processes.

#### 4. Conclusions

We have studied oil and gas trapping in three-phase flow using pore-scale network modeling. The results show some surprising trends with saturation history and wettability due to the complex competition between three-phase displacement processes. It is difficult and time-consuming to investigate the full range of behavior experimentally. Pore-network modeling is a useful tool for understanding multi-phase flow in porous media and, in particular, to determine sensitivities for different displacement processes and wettabilities. It is possible to study a wide range of different displacement scenarios by altering the fluid properties and initial conditions and it may be possible to use the results, eventually, to propose a more physically-based model for three-phase relative permeability than the expressions currently used in the industry.

The increase in oil layer collapse and trapped oil saturation with increasing oil/water contact angle is counter-intuitive: a simple analysis of the problem would predict the opposite behavior. It is only through a careful scrutiny of displacement statistics and fluid configurations that these results can be explained. This illustrates the need to have detailed models of the displacement process that capture the three-phase displacement physics. Furthermore, all these results were obtained from just one set of simulations where water injection started from the same initial configuration in the pore space regardless of wettability; had we considered other saturation paths with more than one water injection cycle, the results may well have been even more complex.

Further work could study the effect of pore structure on trapping using networks representing different rock types; for instance, it has been established experimentally that the amount of trapping increases as the ratio of average pore to throat size (the aspect ratio) increases and as the connectivity of the pore space decreases [16,10].

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