Abstract

Displacement experiments using the porous plate method were conducted on water-wet sandstones to measure the capillary trapping of oil by waterflooding as a function of its saturation after primary drainage. Three sandstone samples ranging in porosity from 12.2% to 22.1% were considered. Experiments on two samples were conducted at an elevated temperature and back-pressure of 343K and 9MPa respectively; experiments on the third sample were conducted at ambient conditions (292 to 297K and 0.06 to 0.17MPa). Residual oil saturation increases monotonically, but with a decreasing gradient, as initial saturation increases.

The dependence of residual saturation on initial saturation is accurately predicted by a two-phase pore-network simulator when a uniform distribution of intrinsic contact angles between 35° and 65° is assumed. The networks were extracted from X-ray microtomography images of small samples of the same rock as those used in the experiments. The laboratory measurements are also accurately described by trapping models proposed by Land (1968) and Spiteri et al. (2008). The residual saturations we measured were higher than in previous displacement experiments, suggesting, for example, that capillary trapping may be an effective way to store substantial quantities of carbon dioxide in aquifers.

Introduction

The trapping of non-wetting phase in a porous medium as discontinuous pore-scale droplets by capillary forces, or capillary trapping, has been studied extensively because of its importance to oil recovery and contaminant remediation. In these applications, the motivation is the extraction of the trapped phase. In contrast, in the context of geological carbon storage, the objective is to maximize trapping. Carbon dioxide (CO₂) is injected into a target geological formation, forming a continuous plume. As the injected CO₂ is driven upwards by buoyancy, ambient groundwater will flow into its wake to replace it. This replacement of CO₂ by groundwater behind the rising CO₂ plume can be regarded as a re-imbibition process. Accordingly, a portion of the migrating CO₂ will be rendered immobile within the pores of the rock by capillary forces, and will no longer be at risk of leakage to the atmosphere provided that local conditions remain unchanged. Further, this process can be enhanced through injection of additional brine (Juanes et al. 2006; Qi et al. 2009).

While many studies report laboratory measurements of capillary trapping in porous media (e.g., Abrams 1975; Agbalaka et al. 2009; Chatzis and Morrow 1984), literature that investigate the dependence of capillary trapping on initial non-wetting phase saturations are more limited. If we further restrict our consideration to experiments in which drainage and imbibition were achieved by displacement of phases within the porous medium, which is the process relevant to carbon storage, and to experiments on uniformly-wet porous media, existing data are limited to those listed in Table 1; a more extensive review of the literature is provided by Pentland et al. (2010). This paper complements these data with new oil/brine coreflooding experiments at flow rates representative of field conditions.

Residual saturation data have traditionally been compared to a number of empirical trapping models. In this paper, our data will be compared to two such models. The first, which is the most widely used in the literature and commercial simulators, was proposed by Land (1968):

\[
S_{\text{res}} = \frac{S_{\text{res}}}{1 + S_{\text{res}} \left( \frac{1}{S_{\text{res}}} - 1 \right)}
\]

(1)
where $S_{nwi}$ and $S_{nwr}$ are the non-wetting phase saturation after primary drainage and after secondary imbibition, respectively, $S_{nwr}^{\max}$ is the maximum $S_{nwr}$, and $S_{wc}$ is the connate wetting phase saturation. The second, a quadratic relationship between initial and residual saturation, was proposed by Spiteri et al. (2008):

$$S_{nwr} = \alpha S_{nwi} - \beta S_{nwi}^2,$$  \hspace{1cm} (2)

where $\alpha$ and $\beta$ are fitting constants. Spiteri et al. (2008) report $\alpha$ and $\beta$ that best-fit their pore-scale simulations of a Berea sandstone using macroscopic intrinsic contact angles ranging from $\theta = 20^\circ$ to $160^\circ$.

Table 1: Studies that report residual saturation as a function of initial non-wetting phase saturation. Only studies that achieved drainage and imbibition by displacement are listed.

<table>
<thead>
<tr>
<th>Source</th>
<th>phases</th>
<th>porous media</th>
<th>porosity</th>
<th>permeability [m$^2$]</th>
<th>symbol in Fig. 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kleppe et al. 1997</td>
<td>air/oil</td>
<td>artificial consolidated medium</td>
<td>0.43</td>
<td>$4.7 \times 10^{-12}$</td>
<td>grey —</td>
</tr>
<tr>
<td>Al Mansoori et al. 2010</td>
<td>air/brine</td>
<td>sand pack</td>
<td>$0.37 \pm 0.002$</td>
<td>$(320 \pm 3) \times 10^{-13}$</td>
<td>green +</td>
</tr>
<tr>
<td>Pentland et al. 2010</td>
<td>oil/brine</td>
<td>sand pack</td>
<td>$0.37 \pm 0.002$</td>
<td>$(320 \pm 3) \times 10^{-13}$</td>
<td>green ×</td>
</tr>
<tr>
<td>Pickell et al. 1966</td>
<td>mercury/oil</td>
<td>Dalton sandstone</td>
<td>0.286</td>
<td>$4.17 \times 10^{-13}$</td>
<td>grey ○</td>
</tr>
<tr>
<td></td>
<td>oil/water</td>
<td></td>
<td>0.248</td>
<td>$1.90 \times 10^{-13}$</td>
<td>grey ◯</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.291</td>
<td>$4.14 \times 10^{-13}$</td>
<td>grey ○</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.286</td>
<td>$2.55 \times 10^{-14}$</td>
<td>grey Δ</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.28</td>
<td>$2.07 \times 10^{-13}$</td>
<td>grey +</td>
</tr>
</tbody>
</table>

Experimental Procedure

Three sandstone samples with porosities 0.221 (Berea), 0.122 (Clashach), and 0.156 (Stainton) were considered. Basic rock properties are summarized in Table 2. All three rocks are considered to be strongly water-wet. All cores were 3.8cm (1.5in.) in diameter and 7.5 to 7.7cm (3.0in.) in length. Experiments were conducted at ambient conditions in the Stainton core and at elevated temperature and pressure (ETP) in Clashach and Berea cores. In the ambient-condition runs, the temperature varied between 292 and 297K (19 to 24°C) and a back-pressure of 0.06 to 0.17MPa was applied. The ETP experiments were conducted inside an air bath at 343K (70°C) with a back-pressure of 9MPa.

The non-wetting phase was $n$-decane in the ETP experiments and $n$-octane in the ambient-condition experiments. This use of different non-wetting liquids is justified, as the estimated interfacial tensions of $n$-octane/water and $n$-decane/water at the relevant experimental conditions only differ by 7% (Table 2). The wetting phase was aqueous 5wt.%-sodium chloride, 1wt.%-potassium chloride synthetic brine. In each ambient-condition run, the density of the fluids was measured at 293.2K using a digital density-meter (Anton Paar DMA48). The average density of brine and $n$-octane across these runs were 1042kg m$^{-3}$ and 702.7kg m$^{-3}$, respectively. The density of the brine and $n$-decane were not measured at ETP, but are expected to be approximately 1030kg m$^{-3}$ (Rogers et al. 1982) and 700kg m$^{-3}$ (Banipal et al. 1991; Lee and Ellington 1965).

Table 2: Petrophysical properties of the core samples and fluid properties used in pore-network simulations.

<table>
<thead>
<tr>
<th>Source</th>
<th>Effective porosity (± standard error)</th>
<th>Brine permeability [m$^2$]</th>
<th>Wetting phase</th>
<th>Non-wetting phase</th>
<th>Interfacial tension [mN m$^{-1}$]</th>
<th>Wetting phase viscosity [Pa·s]</th>
<th>Non-wetting phase viscosity [Pa·s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Berea</td>
<td>0.221 ± 0.001</td>
<td>$5 \times 10^{-13}$</td>
<td>5wt.% NaCl, 1wt.% KCl aqueous solution</td>
<td>n-decane</td>
<td>48.3$^c$</td>
<td>$4.554 \times 10^{-14}$</td>
<td>$5.47 \times 10^{-14}$</td>
</tr>
<tr>
<td>Clashach</td>
<td>0.122 ± 0.003</td>
<td>$8 \times 10^{-14}$</td>
<td>n-octane</td>
<td>51.64±0.04$^c$</td>
<td>$1.0903 \times 10^{-15}$</td>
<td>$5.08 \times 10^{-15}$</td>
<td></td>
</tr>
<tr>
<td>Stainton</td>
<td>0.156 ± 0.001</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Vinogradov et al. 2010.
* Zeppieri et al. 2001; linearly extrapolated to 343K.
* Zeppieri et al. 2001; 293.2 ± 0.1K.
* Kestin, Khalia, and Correia 1981; 5.8wt.% NaCl aqueous solution at 10.0MPa, 343.2K.
* Kestin, Khalia, and Correia 1981; 5.8wt.% NaCl aqueous solution at 100kPa, 293.2K.
* Lee and Ellington 1965; 9480kPa, 344K.
* CRC Handbook of Chemistry and Physics; 298K.
**Coreflooding experiments.** All experiments were conducted in custom-made horizontal Hassler-type core holders (radial confining pressure). A high-precision syringe pump (Teledyne ISCO 1000D or 500D) was used for all wetting and non-wetting fluid displacements. The capillary number was maintained at or below $3 \times 10^{-7}$ during all displacement steps. All cores were cleaned before use by standard Soxhlet extraction with a mixture of methanol and toluene, oven-dried, and weighed.

**Initial water saturation.** The test core was saturated with de-gassed brine at experimental conditions inside the core holder. A minimum of five pore volumes of brine were injected through the core against back pressure. In ambient-condition runs, the core was subsequently removed from the Hassler cell, weighed, and then reinserted into the cell. The Hassler cell, containing the brine-saturated core, was weighed. The pore volume was determined from the increase in mass of the core in ambient-condition runs, and from the increase in mass of the Hassler cell in ETP runs.

**Primary drainage.** The porous plate method, in which a water-wet disk placed immediately downstream of the core retains the non-wetting phase inside the core, was used during primary drainage. With this method, equilibrium corresponds to uniform pressure distribution across the core in each of the phases, with the difference in the equilibrium pressure of the two phases corresponding to the capillary pressure. Capillary end effects are eliminated, and phase saturations are assumed to be uniform across the length of the core.

The non-wetting phase was injected into the core against a back-pressure using one of two methods: at constant pressure or at constant flow rate. The former was used for all experiments with Stainton, for drainage at a capillary pressure $P_c > 1000\text{kPa}$ in Berea, and for drainage at $50\text{kPa} < P_c < 500\text{kPa}$ in Clashach. Here, equilibrium was considered achieved when brine production ceased and the volumetric rate of oil injection by the pump reached a constant (the leakage rate). Capillary pressure, and hence initial saturation, was varied by changing the injection pressure. For all other runs at ETP, a predetermined volume of oil was injected at a constant flow rate corresponding to capillary numbers between $1.6 \times 10^{-10}$ and $3.3 \times 10^{-10}$. Once the volume necessary to achieve the target $S_{\text{nwi}}$ was injected, the system was allowed to equilibrate, and capillary pressure was measured. The duration of primary drainage ranged from 23 to 50 hours for Berea, 22 to 70 hours for Clashach, and 153 to 182 hours for Stainton. $S_{\text{nwi}}$ was determined from the volume of the injected non-wetting phase, the decrease in the mass of the Hassler cell containing the core from its brine-saturated state prior to oil injection and, for ambient-condition runs additionally, from the increase in mass of the Hassler cell during secondary imbibitions for ETP runs and from the decrease in the mass of the core relative to its dry state for ambient condition runs.

**Waterflooding.** Subsequently, the core was flooded with brine in the opposite direction as the oil injection. A minimum of five pore volumes of brine were injected in each ETP run; a minimum of ten pore volumes were injected in the ambient-condition runs. Residual saturation was determined from the decrease in the mass of the Hassler cell containing the core from its brine-saturated state prior to oil injection and, for ambient-condition runs additionally, the volume and the mass of the effluent brine.

**Pore-network simulations.** A corresponding set of simulations of primary drainage and waterflooding were performed using the two-phase flow pore-network simulator developed by Valvatne and Blunt (2004). Input parameters were matched with experimental conditions where possible. We used networks previously extracted (Table 3), using Dong and Blunt (2009)’s algorithm, from X-ray microtomography scans of samples from the same source as the cores in which the laboratory experiments were conducted (Fig. 1). The voxel resolution of the scans was $5.789\mu\text{m} \times 5.789\mu\text{m} \times 5.789\mu\text{m}$ for Berea and Clashach and $17.578\mu\text{m} \times 17.578\mu\text{m} \times 17.578\mu\text{m}$ for Stainton. Interfacial tension, brine viscosity, and oil viscosity were matched with experimental conditions, as listed in Table 2. A receding contact angle of $0^\circ$ was assumed everywhere in the domain to describe a strongly water-wet state during primary drainage. For waterflooding, two values for the macroscopic intrinsic contact angle were considered: $\theta = 15^\circ$ and $50^\circ$. The local intrinsic contact angle was randomly assigned, with equal probability, a value in the range $\theta \pm 15^\circ$. Saturations and relative permeabilities were computed in a sequence of increasing and decreasing capillary pressures for drainage and waterflooding, respectively.
Fig. 1: A two-dimensional section of X-ray microtomography scans of (a) Berea, (b) Clashach, and (c) Stainton samples. Voxel volume (resolution) is $5.789 \mu m \times 5.789 \mu m \times 5.789 \mu m$ in (a) and (b), and $17.578 \mu m \times 17.578 \mu m \times 17.578 \mu m$ in (c). The white horizontal bar in each image depicts 1.00mm.

<table>
<thead>
<tr>
<th></th>
<th>Berea</th>
<th>Clashach</th>
<th>Stainton</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>0.21</td>
<td>0.14</td>
<td>0.16</td>
</tr>
<tr>
<td>Absolute permeability [m²]</td>
<td>$7.8 \times 10^{-13}$</td>
<td>$6.1 \times 10^{-13}$</td>
<td>$1.8 \times 10^{-13}$</td>
</tr>
<tr>
<td>Formation factor</td>
<td>16.0</td>
<td>27.2</td>
<td>55.3</td>
</tr>
</tbody>
</table>

Table 3: Petrophysical properties of the networks used in the pore-network simulations. Clay content was set to zero in all three networks.

Results

**Capillary pressure.** Brine saturation at the end of primary drainage is presented in Fig. 2 as a function of applied capillary pressure, $P_c$. Compared with the experiment are predictions by the pore network simulator (solid lines) and capillary pressure translated from mercury injection capillary pressure (MICP) measurements (Autopore IV 9520; Weatherford Laboratories, Stavanger, Norway) by the classic Leverett-J correlation (Bear 1972; dashed lines)

$$
P_{\text{eq}}(S_w) = \frac{P_{\text{mic}}(S_w)}{\sigma_{\text{Hg}} \cos \theta_{\text{Hg}}} \sigma_{\text{w/b}} \cos \theta_{\text{w/b}},
$$

where $S_w$ is the wetting phase saturation at the end of primary drainage, $\sigma$ is the interfacial tension, and $\theta$ is the macroscopic contact angle, with subscripts Hg and w/b denoting mercury/vacuum systems and oil/brine systems, respectively. Here, $\sigma_{\text{Hg}} = 485$ mN m$^{-1}$, $\theta_{\text{Hg}} = 130^\circ$, and $\theta_{\text{w/b}} = 0^\circ$ were assumed. The capillary pressure curve derived from MICP data agrees very well with ambient-condition measurements in Stainton (Fig. 2c). In contrast, the capillary pressure necessary to establish a given oil saturation during drainage at ETP was significantly larger than values predicted by Eq. 3 from MICP (Fig. 2a, b). This apparent discrepancy is attributed primarily to a premature termination of primary drainage in the ETP experiments (cf. Omorogie 1988). The magnitude of the discrepancy in brine saturations at a given $P_c$ is of the same order of magnitude or smaller than the measured $S_{\text{ov}}$, which indicates that the effect on the initial-residual saturation curves is negligible except at the lowest $S_{\text{ow}}$ (highest brine saturations). The consistent under-prediction of drainage capillary pressure by the pore network simulator, particularly at low brine saturations, has been reported in other studies (Cense and Marcelis 2008; Touati et al. 2009). This is attributed to two reasons. First, capillary pressure measurements do not necessarily record a position of true capillary equilibrium and hence, for a given saturation, may record a higher value than a quasi-static displacement. Second, the resolution of the images – from which the networks were extracted – is too coarse to resolve the fine details of the pore space (cf. Fig. 1). Furthermore, the predicted network permeabilities, Table 3, are consistently higher than the measured permeability, Table 2, indicating an over-estimation of the typical pore size. Indeed, the pore-throat radius distribution estimated from MICP measurements attributes 34.3%, 23.8%, and 99.5% of the pore volume in Berea, Clashach, and Stainton, respectively, to radii smaller than the corresponding voxel resolutions.
Capillary trapping. Residual oil saturations are shown as a function of initial oil saturation in Figs. 3 and 4. Residual saturation increases monotonically, within experimental uncertainty, with increasing initial oil saturation for all samples. The increase is most rapid at low initial saturation and asymptotes at high initial saturation, clearly deviating from a linear dependence. Empirical correlations proposed by Land (1968; Eq. 1) and Spiteri et al. (2008; Eq. 2) are compared with experiment in Fig. 3. Here, $S_{nwr}$ and $S_{wc}$ in Eq. 1 were taken as the mean residual and brine saturation of all runs for which the initial oil saturation is greater than 0.70; the coefficients $\alpha$ and $\beta$ in Eq. 2 were determined by least-squares fitting to data. Both functions yield good agreement with the data.

The best-fit ($\alpha$, $\beta$) for Berea and Clashach were ($\alpha$, $\beta$) = (1.0, 0.5) (Table 4). This set of values was observed in Spiteri et al. (2008)’s simulations in a Berea sandstone network with an imposed macroscopic intrinsic contact angle of $\theta = 70^\circ$ and randomly-assigned local contact angles in the range $\theta \pm 20^\circ$. In contrast, the set of best-fit constants for Stainton, ($\alpha$, $\beta$) = (0.69, 0.15), was not observed by Spiteri et al. (2008), which is not surprising, as this is a different rock sample.

<table>
<thead>
<tr>
<th>Land 1968</th>
<th>correlation coefficient</th>
<th>0.98</th>
<th>0.91</th>
<th>0.92</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spiteri et al. 2008</td>
<td>best-fit fitting parameters</td>
<td>$\alpha = 0.97$; $\beta = 0.49$</td>
<td>$\alpha = 1.0$; $\beta = 0.50$</td>
<td>$\alpha = 0.69$; $\beta = 0.15$</td>
</tr>
<tr>
<td>correlation coefficient</td>
<td>0.98</td>
<td>0.92</td>
<td>0.91</td>
<td></td>
</tr>
</tbody>
</table>

Table 4: Correlation coefficient of data and empirical expressions proposed by Land (1968; Eq. 1) and Spiteri et al. (2008; Eq. 2), and fitting parameters $\alpha$ and $\beta$ as determined by least-squares fitting Eq. 2 to data.
Network model simulations agree well with experimental data in Berea and Clashach when the intrinsic contact angle is assigned uniformly within the range 35° to 65° (Fig. 4a and 4b, solid lines). These are effective local contact angles, accounting for grain roughness, converging/diverging pore geometry, and surface chemistry. This range coincides with the local contact angle distribution identified above by matching to Spiteri et al. (2008)’s simulations and with those used to predict relative permeability measured by Oak (1990) in Berea sandstone by Valvatne and Blunt (2004). In contrast, the network model over-predicts residual saturation in Stainton for both contact angle distributions considered (Fig. 4c). The poor agreement is attributed to the low resolution of the X-ray microtomography images from which the network was extracted (Fig. 1c).

(a)  (b)  (c)

Fig. 4: Comparison of measured (circle) and simulated $S_{nwi}$ in (a) Berea, (b) Clashach, and (c) Stainton cores. Horizontal and vertical bars depict the disagreement between the different methods of saturation estimation for a given run. Where the bars are not visible, they are smaller than the size of the marker or are not available. The horizontal bar on the data point $(S_{nwi}, S_{nwr}) = (0.93, 0.47)$ in (c) extends to $S_{nwi} = 1.04$. Predictions by Valvatne and Blunt (2004)’s pore-network simulator assuming intrinsic contact angles distributed in the range 0° to 30° (dashed line) and 35° to 65° (solid line) are included.

Our laboratory measurements are compared with data reported in the literature in Fig. 5. Only experiments in two-phase, uniformly-wet systems in which the initial saturation was varied systematically and in which both primary drainage and secondary imbibition were achieved by displacement are included. Residual saturation was higher in the present experiments than previous data, which we suggest is related to the complexity of the pore geometry and the lower porosity of the sandstones we considered. Conversely, the lowest residual saturations occurred in porous media with the highest porosity and permeability, namely sand packs (green ×, +) and Kleppe et al. (1997)’s artificial core (grey –). Given this trend, it is interesting to note that the initial-residual saturation curves for Berea and Clashach coincide, despite the two cores having substantially different porosity and permeability (Table 2).
Fig. 5: Laboratory measurements of residual non-wetting phase saturation after wetting-phase flooding or spontaneous imbibition ($S_{nwr}$) as a function of initial non-wetting phase saturation after primary drainage ($S_{nwi}$) in Berea (red ●), in Stainton (blue ■), and in Clashach (yellow ▲) from the present study, in sand packs by Pentland et al. (2010) and Al Mansoori et al. (2010; air/brine), in five Dalton sandstone cores by Pickell et al. (1966), and in an artificial porous medium by Kleppe et al. (1997). For marker definition for data from the literature, see Table 1. Where uncertainty on data from literature is available, they are depicted by horizontal and vertical bars. Horizontal and vertical bars on data from the present study depict the disagreement between the different methods of saturation determination for a given run; where the bars are not visible, they are smaller than the size of the marker or are not available. The horizontal bar on the data point ($S_{nwi}$, $S_{nwr}$) = (0.93, 0.47) for Stainton extends to $S_{nwi}$ = 1.04.

The maximum residual is plotted as a function of porosity in Fig. 6a. Here, the maximum residual is taken as the mean of all runs for which initial oil saturation was greater than 0.70. For the three samples considered here, there is no clear dependence on porosity, contrary to observations of decreasing residual with increasing porosity reported by Jerauld (1997) and Holtz (2005). In contrast, the product of maximum residual saturation and porosity, i.e., the maximum residual as a fraction of the bulk volume, increases monotonically with porosity from 0.122 to 0.221 (Fig. 6b). In the context of carbon storage, this parameter, also referred to as the maximum bulk volume residual (e.g., Weiss et al. 2001), can be interpreted as the capillary trapping capacity of a potential storage site (Iglauer et al. 2009). The data are consistent with previous suggestions that the trapping capacity is largest in rocks with a porosity of around 0.2 (Iglauer et al. 2009).

![Graph showing maximum residual saturation vs. porosity](image)

**Conclusions**

Laboratory measurements of residual non-wetting phase saturation were presented as a function of initial saturation in three water-wet sandstones. The residual saturation increases monotonically, but with a decreasing gradient, with initial saturation.
This trend is captured excellently by the trapping models proposed by Land (1968) and Spiteri et al. (2008). Network modeling on networks that were extracted directly from microtomography images of the pore space accurately predicted the residual saturations when a uniform distribution of intrinsic contact angle between 35° and 65° was assumed. The good agreement indicates that the effective contact angles in the systems we considered are not strongly wetting.

The residual saturations measured in the present study were higher than in previous displacement experiments, suggesting, for instance, that capillary trapping may be an effective way to store substantial quantities of CO2 in aquifers. However, this presumes that super-critical CO2/brine systems have similar wettabilities as in the present experiments; future work will focus on the capillary trapping of CO2 at representative aquifer conditions.

Nomenclature

$P_c$ = applied capillary pressure, Pa  
$S_{nwi}$ = initial (post-primary drainage) non-wetting phase saturation  
$S_{nwr}$ = residual (post-imbibition) non-wetting phase saturation  
$S_w$ = wetting phase saturation  
$S_{wc}$ = connate (irreducible) wetting phase saturation  
$\alpha$ = fitting parameter in Eq. 2  
$\beta$ = fitting parameter in Eq. 2  
$\sigma$ = interfacial tension, N m$^{-1}$  
$\theta$ = macroscopic intrinsic contact angle, °

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