Direct pore-to-core up-scaling of displacement processes: Experimentation and dynamic pore network modeling

Arash Aghaei ^a, Mohammad Piri ^{a,*}

^a *Department of Chemical and Petroleum Engineering, University of Wyoming, Laramie, Wyoming, USA.*

Abstract

We present a new dynamic pore network model that is capable of up-scaling two-phase flow processes from pore to core. This dynamic model provides a platform to study various flow processes in porous media at the core scale using the pore-scale physics. The most critical features of this platform include (1) the incorporation of viscous, capillary, and gravity pressure drops in pore-scale displacement thresholds, (2) wetting-phase corner flow in capillary elements with angular cross-sections, (3) adjustments of corner interfaces between wetting and non-wetting phases based on changes in local capillary pressure, (4) simultaneous injection of wetting and non-wetting phases from the inlet of the medium at constant flow rates that makes the study of steady-state processes possible, (5) heavy parallelization using a three-dimensional domain decomposition scheme that enables the study of two-phase flow at the core scale, and (6) constant pressure boundary condition at the outlet. For the validation of the dynamic model, three two-phase miniature core-flooding experiments were performed in a state-of-the-art micro core-flooding system

*Corresponding author. E-mail address: mpiri@uwyo.edu.

integrated with a high-resolution X-ray micro-CT scanner. The dynamic model was rigorously validated by comparing the predicted local saturation profiles, fractional flow curves, relative permeabilities, and residual oil saturations against their experimental counterparts. The validated dynamic model was then used to study low-IFT and high viscosity two-phase flow processes and investigate the effect of high capillary number on relative permeabilities and residual oil saturation.

Keywords:

Up-scaling, Pore-scale flows, Pore network modeling, Microtomography, Core-flooding experiments

1. Introduction

Multiphase flow in porous media occurs in many natural and artificial processes such as subsurface flow of hydrocarbons and brine, geologic storage of CO₂, non-aqueous phase liquids (NAPL) migration in soil, reactive transport, and water removal in gas diffusion layer (GDL) of proton exchange membrane (PEM) fuel cells. Understanding the displacement and transport processes relevant to multiphase flow systems and predicting the associated macroscopic properties are crucial for design and prediction of performance of these processes (Dullien, 1992; Sahimi, 2010).

In petroleum and environmental engineering contexts, multiphase flow in porous rocks has been studied extensively using experimental and numerical techniques at multiple scales. Large-scale continuum models (e.g. reservoir models) generally solve mass conservation partial differential equations over grid blocks of the medium that are larger than (or equal to) Representa-

15 tive Elementary Volume (REV) of that medium. These models read as input
 16 multiphase flow functions such as relative permeabilities. These functions are
 17 manifestation of many pore-scale phenomena, and they inform the numerical
 18 solvers of mass conservation equations about the underlying displacement
 19 physics. Pore-scale investigations are often used to develop improved under-
 20 standing of fundamental phenomena relevant to a given process and predict
 21 the pertinent flow and transport properties. These physically-based proper-
 22 ties are then used to inform the larger-scale continuum models.

23 The pore-scale models can be categorized into direct and network mod-
 24 els. In direct models, multiphase flow is simulated directly in the pore space
 25 structure that is mapped using an imaging technique or created by a process-
 26 based reconstruction method, e.g., sedimentation simulation. Direct mod-
 27 els include Lagrangian particle-based (mesh-free) methods, such as moving
 28 particle semi-implicit (MPS) (Koshizuka et al., 1995; Premože et al., 2003;
 29 Ovaysi and Piri, 2010, 2011), smoothed particle hydrodynamics (SPH) (Gin-
 30 gold and Monaghan, 1997; Zhu et al., 1999; Tartakovsky and Meakin, 2005),
 31 and Lattice Boltzmann (Inamuro et al., 2004; Li et al., 2005), and mesh-
 32 based methods, e.g., finite element (Fourie et al., 2007). These models use
 33 accurate representation of the pore space. However, due to irregular fluid-
 34 solid boundaries and deformability of fluid-fluid interfaces, direct models are
 35 computationally expensive and may not be suitable for studying multiphase
 36 flow at the core scale. In the second group of pore-scale models, i.e., net-
 37 work models, the pore space is represented by a network of idealized pores
 38 and throats. Pore-scale displacements are carried out in the pore network to
 39 simulate multiphase flow (Øren et al., 1998; Patzek, 2001; Blunt et al., 2002;

40 Piri and Blunt, 2005a,b).

41 Pore network modeling was first introduced in the 1950's by Fatt (1956a,b,c)
42 who used a network of real resistors to calculate relative permeability and
43 capillary pressure for a drainage process. Network modeling, since its intro-
44 duction, has evolved enormously. Today, one can map the pore space of a
45 rock sample with high-resolution imaging techniques and extract an equiva-
46 lent pore network (Dong and Blunt, 2009). Our knowledge of the pore-scale
47 displacement physics has also improved dramatically due to micro-fluidics
48 and other types of experiments. Pore network models can be divided into
49 quasi-static and dynamic. The majority of the previously-developed net-
50 work models are quasi-static in which the pore-scale displacements take place
51 based on their threshold capillary pressure. These models have had signif-
52 icant success in modeling two- and three-phase flow in porous media under
53 capillary-dominated conditions (Øren et al., 1998; Patzek, 2001; Øren and
54 Bakke, 2003; Valvatne and Blunt, 2004; Piri and Blunt, 2005a,b). However,
55 quasi-static models do not include the effects of viscous and gravity forces,
56 and therefore, cannot be used to study cases in which capillary-dominated as-
57 sumptions do not apply. Viscous and gravity forces become significant during
58 many subsurface flow processes, such as enhanced oil recovery (EOR) meth-
59 ods of polymer and surfactant flooding, and high velocity flow regimes that
60 are encountered in naturally and hydraulically induced fractures as well as
61 near well-bore areas (Lake, 1989; Sahimi, 2010). In these cases, the combined
62 effects of capillary, viscous, and gravity forces determine the flow behavior in
63 porous media. In dynamic network models, on the other hand, viscous and in
64 some cases gravity forces are taken into account. These models can be used

65 to study the cases in which viscous or gravity forces are relevant. However,
66 due to various reasons, such as difficulties in implementing the complex pore-
67 scale physics and the computational costs associated with these models, the
68 previously-developed dynamic models lack some of the critical capabilities to
69 successfully simulate dynamic two-phase flow processes at the core scale.

70 Tables 1 and 2 list the previously-developed dynamic pore network models
71 along with their largest network size, phenomena studied, and validation
72 techniques. A comprehensive review of dynamic pore network models of two-
73 phase flow in porous media can be found elsewhere, see, Joekar-Niasar and
74 Hassanizadeh (2012) and Aghaei (2014). Here, we discuss the characteristics
75 and predictive capabilities of each previously-developed model. We then
76 present an overview of the dynamic model developed under this study and
77 explain the critical relevance of its capabilities within the context of direct
78 up-scaling.

79 Koplik and Lasseter (1985) developed the first dynamic network model
80 to study the effects of microscopic pore structure on macroscopic phenom-
81 ena. They stated the computational difficulties associated with dynamic
82 pore network modeling as the limiting constraint in selecting the network
83 size. Lenormand et al. (1988), Blunt and King (1991), and Lee et al. (1995)
84 developed models in which the pores contained all the fluid and the pres-
85 sure drops took place exclusively in the throats. Lenormand et al. (1988)
86 performed drainage simulations at various capillary numbers and viscosity
87 ratios and identified three distinct flow patterns. Blunt and King (1991) ran
88 drainage simulations in two- and three-dimensional random networks and cal-
89 culated relative permeabilities based on local flow rates and pressure drops.

90 The model developed by Lee et al. (1995) was a parallel model that was used
91 to perform water-flooding and miscible-flooding simulations in networks as
92 large as 524,288 pores. This model was later extended by Kamath et al.
93 (1996) and Xu et al. (1999) who were able to reproduce recoveries in a
94 fully *miscible* core-flooding experiment in a dolomite sample.

95 van der Marck et al. (1997) extended the model introduced by Lenor-
96 mand et al. (1988) by allowing up to two menisci in pore throats. Mogensen
97 and Stenby (1998) developed a model in which the corner flow and snap-
98 off displacements were incorporated. Aker et al. (1998) developed a model
99 with hourglass-shaped throats to study time dependencies of pressure dis-
100 tribution and fluid front in drainage processes. Later, Knudsen and Hansen
101 (2002) modified this model by adding biperiodic boundary conditions. Dahle
102 and Celia (1999) introduced a new interface tracking method in which flu-
103 ids could form compartments that were separated by fluid-fluid interfaces.
104 Hughes and Blunt (2000) used the wetting-phase viscous pressure drop to
105 perturb the order of displacements. This quasi-dynamic model was used to
106 study the effect of the capillary number during imbibition. Constantinides
107 and Payatakes (2000) studied the effects of wetting layers on disconnection
108 of the non-wetting phase during imbibition. Thompson (2002) created ran-
109 dom pore networks with converging-diverging geometry for throats to study
110 drainage and imbibition in fibrous materials. Singh and Mohanty (2003) in-
111 troduced a new method for handling the corner flow in which the wetting
112 phase was removed from the layers in proportion to the local capillary pres-
113 sure drop. Nordhaug et al. (2003) extended the model developed by Blunt
114 and King (1991) to study interfacial velocities and areas. Løvoll et al. (2005)

115 studied drainage of a high-viscosity wetting phase and stabilizing effect of
 116 gravity using a dynamic pore network model and glass beads experiments.
 117 Al-Gharbi and Blunt (2005) incorporated layer swelling and snap-off dis-
 118 placements in a dynamic model and used it to study the effects of capillary
 119 number and viscosity ratio in drainage in 2D lattices. Nguyen et al. (2006)
 120 introduced a new network model to study the competition between snap-off
 121 and piston-like displacements during imbibition and its effect on relative per-
 122 meabilities and residual oil saturation. The only dynamic effect included in
 123 this model was the viscous pressure drop associated with the wetting films.
 124 DiCarlo (2006) used a quasi-dynamic network model to study the saturation
 125 overshoot behind infiltration fronts. The model included the viscous pres-
 126 sure drop of the wetting phase during imbibition. Piri and Karpyn (2007)
 127 created a pore network representation of fracture void space from the frac-
 128 ture aperture map obtained through X-ray microtomography. They used a
 129 quasi-dynamic network model to simulate two-phase flow in a single fracture
 130 (Karpyn and Piri, 2007). Joekar-Niasar et al. (2010) studied the qualita-
 131 tive behavior of non-equilibrium capillary pressure theory (Stauffer, 1978;
 132 Hassanizadeh and Gray, 1990) using a dynamic network model. Tørå et al.
 133 (2012) extended the model developed by Aker et al. (1998) by incorporating
 134 the dynamics of the wetting layers using an approach similar to Singh and
 135 Mohanty (2003). They used this model to study saturation profiles during
 136 imbibition and the resistivity index at different capillary numbers. Sheng
 137 and Thompson (2013) extended the dynamic pore network model developed
 138 by Thompson (2002), and coupled it with a continuum-scale reservoir simu-
 139 lator. The coupling was performed by embedding pore networks inside a few

140 gridblocks of the reservoir simulator.

141 Based on the literature review presented above, it is clear that while there
142 have been numerous dynamic network modeling studies in the past, there is
143 still a need for a physically-based dynamic network model capable of model-
144 ing pore-scale displacements in random networks and up-scaling them to the
145 core scale. The previously-developed dynamic network models that include
146 the complex pore-scale physics (Al-Gharbi and Blunt, 2005; Mogensen and
147 Stenby, 1998; Dahle and Celia, 1999) lack the sufficient computational per-
148 formance and can model two-phase flow in networks of few hundred to few
149 thousand pores, and the ones that are capable of simulating flow in larger
150 pore networks (Lee et al., 1995; Kamath et al., 1996; Xu et al., 1999) lack
151 the necessary pore-scale physics such as the wetting-phase corner flow and
152 snap-off displacements to quantitatively predict the multiphase flow proper-
153 ties.

154 We introduce an entirely new dynamic network model to perform physically-
155 based up-scaling of displacement processes from pore to core scale. The
156 model takes into account viscous, capillary, and gravity forces as well as wet-
157 tability effects. It incorporates all relevant displacement mechanisms and
158 allows for variations in the order by which they take place under different
159 flow regimes in response to changes in the capillary and Bond numbers. The
160 wetting-phase corner flow with variable corner interface location responsive
161 to changes in local capillary pressure is included in the model. Simultaneous
162 injection of wetting and non-wetting fluids with constant flow rates from the
163 inlet has been incorporated in the model, and it has enabled us to study the
164 steady-state two-phase flow processes. Constant pressure boundary condition

165 is used at the outlet. This platform is developed to run on massively parallel
166 computer clusters and to bridge the gap between pore-scale displacements
167 and core-scale processes.

168 In order to validate the model presented here, we performed three two-
169 phase miniature core-flooding experiments. The experiments were performed
170 in a state-of-the-art core-flooding apparatus integrated with a high-resolution
171 micro-CT imaging system. For the first time in pore-scale modeling litera-
172 ture, the in-situ contact angles measured from high-resolution micro-CT im-
173 ages of the pore space during experiments were used to design contact angle
174 distributions in the digital pore network. Using the dynamic model, simu-
175 lations were performed with identical flow rates and fluid properties as the
176 experiments. The dynamic model was then rigorously validated by compar-
177 ing the local saturation profiles, relative permeabilities, and fractional flow
178 curves obtained from simulations against their experimental counterparts.
179 The validated model was then used to study different dynamic processes
180 that occur in, for instance, many enhanced oil recovery schemes.

181 In this paper, first, we give a detailed description of the dynamic model
182 and techniques used to model two-phase flow at the core scale. Then, the
183 miniature core-flooding experiments that are performed for the validation of
184 the model are described in detail. This is followed by a rigorous validation
185 of the simulation results against their experimental counterparts. The vali-
186 dated model is then used to study low-IFT and high viscosity flow processes.
187 The dynamic effects observed in these high capillary number simulations are
188 discussed in detail. Finally, we include a set of conclusions and final remarks.

189 2. Model Description

190 2.1. Network Representation of the Porous Medium

191 We use three-dimensional random networks that are generated from high-
192 resolution micro-CT images of the rock samples used in the experiments
193 presented here (see Dong and Blunt (2009) for more details on the network
194 generation method). Two different pore networks representing the pore space
195 in Bentheimer and Berea rock samples were used in this work. A 17 mm long
196 section at the middle of the Berea core sample was scanned at a resolution of
197 $2.49 \mu\text{m}$. A pore network with a length of 16.3 mm and a square cross section
198 of $3.11 \times 3.11 \text{ mm}^2$ was generated. Twenty replicates of the 16.3 mm long
199 Berea network were connected to build a larger network. Average properties
200 from the original network (e.g., coordination number and throat radii) were
201 used at the connection sites. A cylindrical pore network with a length of 76.4
202 mm and a diameter of 4.58 mm was cut from the larger network. We refer
203 to this network as the Berea network hereinafter. The Bentheimer network
204 was built using a similar approach.

205 The dimensions and petrophysical properties of the Bentheimer and Berea
206 networks are listed in Tables 3 and 4, respectively. The pores and throats of
207 our networks have rectangular, scalene triangular, and circular cross sections.
208 Figure 1(a) shows a volume rendered gray scale image of the Berea sand-
209 stone core sample. This gray scale image is segmented using the histogram
210 thresholding technique producing a pore-grain separated labeled image seen
211 in Figure 1(b), where red and gray colors represent the pore and grain vox-
212 els, respectively. The gray-scale and pore-grain separated images are used to
213 construct a pore network representative of the Berea core sample, as shown

214 in Figure 1(c). In the pore network image, pores and throats are shown with
 215 red spheres and blue cylinders, respectively. Figure 1(d) shows a magnified
 216 image of a small section of the Berea pore network.

217 *2.2. Model Assumptions*

218 In this model, fluids are assumed to be Newtonian, incompressible, and
 219 immiscible. Fluid-fluid interfaces are assumed to be sharp with no diffusion
 220 taking place between two phases. Fluid flow inside pores and throats is de-
 221 scribed by Stokes or creeping flow. The clay inside the pore-space is assumed
 222 to be fully saturated with immobile water.

223 *2.3. Pore-Scale Displacements*

224 A series of pore-scale fluid displacements are carried out in the pore net-
 225 work to simulate two-phase flow displacements in porous media. Three funda-
 226 mental types of pore-scale displacement mechanisms included in this dynamic
 227 model are piston-like, pore-body filling (cooperative filling), and snap-off.

228 The simulations start with fully water saturated pores and throats where
 229 all possible displacements from the inlet have been added to the system.
 230 Displacements occur in the order of highest-to-lowest *displacement potential*
 231 (see section 2.4) that takes into account the effects of capillary, viscous, and
 232 gravitational pressure drops. After each displacement, new displacements
 233 are added to the system based on the access of fluid phases to each other.

234 *2.4. Displacement Pressure Drop and Sequence*

235 The multiphase flow behavior in porous media is determined by the inter-
 236 linked effects of capillary, viscous, and gravity forces. Therefore it is essential

237 to include the effects of these three basic forces in the model. In this work,
 238 this is achieved by combining the capillary, viscous, and gravitational pres-
 239 sure drops of a displacement into a new parameter called the *displacement*
 240 *pressure drop* as given by equation (1).

$$\Delta P_{\text{disp}} = \Delta P_{\text{cap}} + \Delta P_{\text{visc}} + \Delta P_{\text{grav}} \quad (1)$$

$$N_c = \frac{\mu\nu}{\sigma} \quad (2)$$

$$Bo = \frac{\Delta\rho g L^2}{\sigma} \quad (3)$$

241 The contribution of each term in the displacement pressure drop to its
 242 total value depends on the capillary and Bond numbers (equations (2) and
 243 (3)). In the cases where the capillary and Bond numbers are both very low,
 244 capillary pressure dominates the flow behavior in porous media. However by
 245 increasing the capillary and Bond numbers the contributions of viscous and
 246 gravitational pressure drops, respectively, become more significant.

247 For piston-like displacements we use the Mayer-Stowe-Princen (MSP)
 248 method to calculate the capillary pressure drop of displacements (Mayer
 249 and Stowe, 1965; Princen, 1969a,b, 1970; Øren et al., 1998; Piri and Blunt,
 250 2005a). In this method, an energy balance equation is written for the fluid
 251 configuration changes associated with a pore-scale displacement. By assum-
 252 ing the equilibrium conditions at constant temperature and combining the
 253 resultant equation with the Young-Laplace equation, the capillary pressure
 254 drop during a fluid configuration change is obtained.

$$\Delta P_{\text{visc}} = (P_{\text{inlet}}^{\text{invd}} - P_{\text{elm}}^{\text{invd}}) + (P_{\text{elm}}^{\text{def}} - P_{\text{outlet}}^{\text{def}}) \quad (4)$$

255 The viscous pressure drop occurs due to the friction between layers of fluid
 256 that move with different velocities. We calculate the viscous pressure drop
 257 for *both* the invading and defending fluid phases. For the invading fluid phase
 258 the viscous pressure drop is calculated from the inlet of the pore network to
 259 the displacement location, and for the defending fluid phase, it is calculated
 260 from the displacement location to the outlet of the pore network as written
 261 in equation (4).

$$\Delta P_{\text{grav}} = (\rho^{\text{invd}} - \rho^{\text{def}})gh_{\text{elm}} \quad (5)$$

262 The gravitational pressure drop is the result of the hydrostatic pressure
 263 difference of the invading and defending fluid phases as given by equation (5),
 264 where ρ^{invd} and ρ^{def} are the densities of the invading and defending phases,
 265 respectively, g is the acceleration of gravity, and h_{elm} is the height of the pore
 266 or throat involved in the displacement measured from the injection face of
 267 the medium.

$$\Phi_{\text{disp}} = P_{\text{inlet}}^{\text{invd}} - P_{\text{outlet}}^{\text{def}} - \Delta P_{\text{disp}} \quad (6)$$

268 Whether pore-scale displacements can take place and their sequence are
 269 determined by a parameter called the *displacement potential*. The displace-
 270 ment potential is defined as the difference of the *driving force* and the dis-
 271 placement pressure drop. The driving force is defined as the difference of the
 272 inlet pressure of the invading phase and the outlet pressure of the defending
 273 phase. The displacement potential for any given displacement is calculated

274 using equation (6). Displacements can take place only if they have a positive
 275 potential, and they take place in the order of highest-to-lowest displacement
 276 potential.

277 2.5. Volume Balance and Pressure Calculations

278 Fluid phase pressure field calculation is regarded as the backbone of this
 279 dynamic model. The pressure field is obtained by writing volume balance
 280 equations for center and corner phases at each pore and solving the resulting
 281 system of linear equations with the appropriate boundary conditions.

$$\sum_{j=1}^n q_{ij} = 0 \quad (7)$$

282 Equation (7) gives the volume balance for pore i where q_{ij} is the flow rate
 283 between pores i and j , and n is the coordination number of pore i . For a
 284 pore that contains the non-wetting phase at its center and the wetting phase
 285 at its corners, this equation is written twice, once for the center phase and
 286 another time for the corner phase.

287 There are six possible configurations of two fluid phases in an assembly
 288 of two pores and a throat as shown in Figure 2. Pores and throats are
 289 shown by circles and cylinders for illustrative purposes only. They can have
 290 angular cross sections and contain center and corner phase locations. In
 291 configurations 1 and 4, no *Main Terminal Meniscus* (MTM) exists between
 292 pores i and j , therefore the single phase flow equations are written for the
 293 center and corner phases of these configurations.

$$q_{ij}^p = g_{ij}^p (P_i^p - P_j^p) \quad (8)$$

$$\frac{1}{g_{ij}^p} = \frac{1}{g_{pore,i}^p} + \frac{1}{g_{throat,ij}^p} + \frac{1}{g_{pore,j}^p} \quad (9)$$

Equation 8 gives the corner flow and single-phase center flow, where g_{ij}^p is the equivalent conductance of fluid phase p between pores i and j , and P_i^p and P_j^p are pressures of fluid phase p in pores i and j , respectively. g_{ij}^p is calculated through equation 9.

$$P_c^{\text{config},2} = P_i^o - P_j^w \quad (10)$$

$$\Phi_{\text{config},2}^{\text{dra}} = P_c^{\text{config},2} - P_{c,ij}^{\text{dra}} \quad (11)$$

$$\Phi_{\text{config},2}^{\text{imb}} = P_{c,i}^{\text{imb}} - P_c^{\text{config},2} \quad (12)$$

$$q_{ij} = \begin{cases} g_{ij}^{ce}(P_i^{nw} - P_j^w - P_{c,ij}^{\text{dra}}) & \text{if } \Phi_{\text{config},2}^{\text{dra}} > \Phi_{\text{config},2}^{\text{imb}} \quad \text{and} \quad \Phi_{\text{config},2}^{\text{dra}} > 0 \\ g_{ij}^{ce}(P_i^{nw} - P_j^w - P_{c,i}^{\text{imb}}) & \text{if } \Phi_{\text{config},2}^{\text{imb}} > \Phi_{\text{config},2}^{\text{dra}} \quad \text{and} \quad \Phi_{\text{config},2}^{\text{imb}} > 0 \\ 0 & \text{if } \Phi_{\text{config},2}^{\text{dra}} < 0 \quad \text{and} \quad \Phi_{\text{config},2}^{\text{imb}} < 0 \end{cases} \quad (13)$$

In configurations where one or two MTM's exist between two pores (see Figure 2), two-phase flow equations are used to describe the center flow between the pores. The center flow equations for configuration 2 will be discussed here. In configuration 2, one oil-water MTM is located at the entrance of throat ij . The MTM can either move into throat ij and cause a drainage-type flow, or retreat into pore i and cause an imbibition-type flow depending on the local capillary pressure and threshold capillary pressures of pore i and throat ij . Local capillary pressure for configuration 2 is written as

the difference of oil pressure in pore i and water pressure in pore j (equation (10)). The potentials for two possible types of the MTM movement in configuration 2 are given by equations (11) and (12), where $P_{c,ij}^{\text{dra}}$ is the drainage threshold capillary pressure of throat ij and $P_{c,i}^{\text{imb}}$ is the imbibition threshold capillary pressure of pore i . As written in equation (13), if the drainage potential of the MTM is positive and greater than its imbibition potential, then a drainage-type flow will be considered for the MTM. However, if the imbibition potential is positive and greater than the drainage potential, then an imbibition-type flow will be considered for the MTM. In cases where both potentials are negative there will be no two-phase flow taking place between pores i and j .

$$\frac{1}{g_{ij}^{ce}} = \frac{1}{g_{pore,i}^{nw}} + \frac{1}{g_{throat,ij}^w} + \frac{1}{g_{pore,j}^w} \quad (14)$$

The equivalent center flow conductance, g_{ij}^{ce} , in configuration 2, is calculated through equation 14. The center flow conductances are calculated by using the equations proposed by Øren et al. (1998) and Patzek and Silin (2001), while the corner flow conductances are calculated by equations proposed by Hui and Blunt (2000).

The resultant system of linear equations is solved by using the the MUMPS package, which is a massively parallel sparse matrix solver (Amestoy et al., 2001, 2006).

2.6. Boundary Conditions

In order to replicate the experimental conditions during simulations and to be able to study steady-state two-phase flow processes, wetting and non-wetting fluids are injected simultaneously at constant flow rates from the inlet

329 of the medium. This is similar to the work by Hashemi et al. (1998, 1999b,a)
 330 in which both the wetting and non-wetting fluids act as the invader and the
 331 defender. In our model, drainage and imbibition processes are simulated by
 332 changing the inlet flow rates. The direction in which the inlet flow rates
 333 change determines the type of two-phase flow process we simulate.

$$\sum_{j=1}^n q_{ij}^p = q_{inlet}^p \quad (15)$$

334 Material balance is written for the inlet as shown in equation (15) where
 335 q_{inlet}^p is the flow rate of phase p at the inlet. Pressures of wetting and non-
 336 wetting phases at the inlet are obtained by solving the material balance
 337 equations.

338 At the outlet of the medium, constant pressure boundary conditions are
 339 enforced. Since the *local* capillary pressure at the pore scale cannot be zero,
 340 a non-zero capillary pressure is enforced at the outlet. The outlet capil-
 341 lary pressure has the value below which no network-spanning cluster of the
 342 non-wetting phase can exist in the system. During drainage, when the non-
 343 wetting phase reaches the outlet of the network, the pressures of the wetting
 344 and non-wetting fluids are averaged in a partition of the network adjacent to
 345 the outlet, and capillary pressure is determined in that partition. This capil-
 346 lary pressure is set as the outlet capillary pressure. However, if the capillary
 347 number is high, the outlet capillary pressure can be overestimated using this
 348 method. Therefore, the capillary pressure set at the outlet is reduced gradu-
 349 ally in small increments to find the value below which the connection of the
 350 non-wetting phase to the outlet is lost completely. This critical value is set
 351 as the outlet capillary pressure. This procedure is performed automatically

352 by the model as soon as the breakthrough of the non-wetting phase occurs.
 353 The outlet capillary pressure is kept constant during the simulations. One
 354 should note that the values set as the outlet capillary pressure are insignifi-
 355 cant compared to the macroscopic pressure drops along the network.

356 2.7. Corner Interface Handling

357 The location of *Arc Menisci* (AM's) determine the area open to corner
 358 and center flows and have a significant impact on pressure values and thereby
 359 relative permeabilities as well as other predicted properties. This dynamic
 360 model allows the location of AM's to be updated based on the local capillary
 361 pressure and receding and advancing contact angles. This is similar to the
 362 approach that is often used in quasi-static network models in determining
 363 threshold capillary pressure for a snap-off displacement.

$$P_c = \sigma_{ob} \left(\frac{1}{r_1} + \frac{1}{r_2} \right) \quad (16)$$

364 When a new AM is formed in a pore element, its location is determined
 365 by calculating its distance from the apex of the corner in which it is formed.
 366 The Young-Laplace equation (equation (16)) combined with a geometrical
 367 relationship is used to determine the apex-meniscus distance. After an AM
 368 is formed, the local capillary pressure might change due to changes in fluid
 369 phase pressure distribution. The *moving contact angle* (θ_{mov}) is defined as the
 370 contact angle with which a fluid-fluid interface moves and it has a constant
 371 value during the interface movement. When the local capillary pressure in
 372 a pore element changes, an AM in the pore element will move only if its
 373 contact angle is equal to θ_{mov} , otherwise the AM will hinge and its contact

angle will change by keeping a fixed apex-meniscus distance. As an example, as shown in Figure 3(a), if P_c increases and the contact angle is equal to the receding contact angle, then the AM will move toward the corner apex with a fixed contact angle. In Figure 3(b), on the other hand, P_c decreases, and the contact angle is lower than the advancing contact angle, therefore the AM will hinge away from the corner apex with a fixed apex-meniscus distance.

2.8. Parallelization

The computational challenges in dynamic network models have limited the size of the mediums that were studied with previously-developed models (see Tables 1 and 2). They have also hindered studies of heterogeneous mediums at the pore scale. Calculating the fluid phase pressure field and updating the fluid-fluid interface locations and displacement potentials at each time step, and updating the continuity flags of neighboring fluid phase locations after each displacement are computationally the most demanding steps in this dynamic model. We take advantage of greater memory and computational resources available on massive computer clusters. Data parallelism through three-dimensional domain decomposition was employed in designing the parallel algorithms.

In Figure 4, a domain decomposition scheme is illustrated, in which the domain of the problem is divided into, in this case, 27 subdomains and each subdomain is assigned to one processor. In this work, the pore network is divided into multiple blocks based on the availability of the computational resources, and each block is assigned to one processor. The pores and throats whose center coordinates lie inside the boundaries of a block are considered as *local* elements to that block and their information is stored on the memory

399 of the processor assigned to that block. The computations related to a pore
 400 or throat are done by the processor to which the element is local. Consider
 401 two neighboring blocks A and B as shown in Figure 5. Pore i and throat
 402 ij are local to block A, which is assigned to processor a, and pore j is local
 403 to block B, which is assigned to processor b. Processor a is responsible for
 404 computations related to pore i and throat ij , and processor b is responsible
 405 for computations related to pore j . However, during some computations,
 406 processors a and b might also need the information related to pore j and
 407 throat ij , respectively. Therefore pore j and throat ij are considered as *inter-*
 408 *block* elements to blocks A and B, respectively, and part of their information
 409 needs to be stored in the memory of their respective processors as well. The
 410 information related to inter-block elements such as fluid phase occupancy and
 411 pressures needs to be communicated during simulations between neighboring
 412 processors. MPI (Message Passing Interface) (Gabriel et al., 2004) libraries
 413 are used to carry out communications between processors in this model.

414 2.9. The Model Algorithm

415 The general outline of the model is explained in this section. Algorithm
 416 flow chart of the model is presented in Figure 6. The first step is reading the
 417 simulation parameters and the network data and decomposing it among the
 418 available processors. Then, the initial fluid phase is assigned to the pores and
 419 throats and the isolated elements are detected in the pore network. A parallel
 420 clustering algorithm is developed for the cluster detection in a decomposed
 421 domain. Next, the absolute permeability and porosity of the pore network
 422 are calculated. By examining the elements connected to the inlet of the
 423 network, all possible displacements from the inlet are detected and added to

424 the displacement lists.

425 Now that the model has been initialized, the first flow-rate step is started
426 by setting the first pair of wetting and non-wetting phase flow rates as the
427 inlet boundary condition. The pressure field is computed with the new inlet
428 flow rates. Using an iterative procedure the pressure calculation, corner in-
429 terface update, area-volume calculations, and phase conductance calculations
430 are repeated until the pressure values converge. The available volume of each
431 phase during a time step is calculated and the most favorable displacement is
432 detected. If the available volume is sufficient to carry out the most favorable
433 displacement, the displacement takes place. Otherwise the simulation goes
434 to the next time step. After each displacement, new pore-scale displacements
435 are detected and added to the system. The displacements continue to take
436 place until no displacement with a positive potential is left. At that point,
437 the system has reached the steady-state condition. The relative permeabili-
438 ties, phase saturations, pressure distributions, and fluid occupancy data are
439 reported at steady-state points. The simulation ends if it is at the final
440 flow-rate step. Otherwise it goes to the next flow-rate step.

441 **3. Experiments**

442 To validate our dynamic pore network model, we conducted three sets
443 of two-phase miniature core-flooding experiments in Betheimer and Berea
444 sandstone core samples. The experiments were performed using a state-
445 of-the-art core-flooding apparatus integrated with a high-resolution X-ray
446 micro-computed tomography imaging system. In this section, the experimen-
447 tal procedures and conditions, fluid and rock properties, flow rates, image

segmentation and analysis techniques, in-situ contact angle measurements, and pressure drop analysis method are described. The experimental setup used in this work is described in Alizadeh et al. (2014) and Khishvand et al. (2014) as well.

3.1. Experimental Procedures and Conditions

Table 5 lists the experiment numbers along with the core samples, experimental procedure and conditions, and fluids used in this study.

Dimensions and petrophysical properties of the core samples are listed in Table 6. Figure 7 shows the Berea sandstone core sample used in this work along with its pore network representation. An automated helium porosimeter-permeameter that employs a pressure decay technique was used to measure porosity and absolute permeability of a large Bentheimer core sample from which we cut the miniature samples for the experiments. Porosity was also obtained from high-resolution micro-CT images of the core samples. Porosity values obtained from the helium porosimeter-permeameter and high-resolution micro-CT images were in agreement. Brine permeability was measured for the Berea sandstone core sample.

Properties of the fluids used in the experiments are listed in Table 7. Viscosity measurements were performed at the experimental temperature and pressure conditions for each fluid using an electromagnetic viscometer. Densities of the fluids were measured at the experimental temperature and ambient pressure conditions using a DMA 5000 density meter that utilizes the oscillating U-tube method. Densities were not expected to change significantly at the experimental pressures of 0.90 and 2.76 MPa. IFT values were measured at the experimental temperature and pressure conditions us-

473 ing a high pressure pendent drop technique (see Saraji et al. (2013) for more
474 details on the experimental method).

475 Each experiment was started with a fully brine saturated core sample
476 ($S_w=1$), that was vertically placed in the core-flooding apparatus. The sam-
477 ple was held inside a custom-built micro core holder made of carbon fiber. It
478 was kept under confining pressure. All the wetted parts of the core holder and
479 the core-flooding system were made of Hastelloy or other corrosion resistant
480 material. The fluids were injected from the bottom of the core. Experiments
481 1 and 2 were performed using the steady-state method meaning that both
482 the wetting and non-wetting fluids were injected during each test. In these
483 experiments, the drainage tests were performed by gradually reducing the
484 brine flow rate and increasing the oil flow rate. The imbibition tests were
485 started after the drainage tests by increasing the brine flow rate and decreas-
486 ing the oil flow rate. Tables 8 and 9 list the brine and oil flow rates and
487 their corresponding capillary numbers in Experiments 1 and 2, respectively.
488 In Experiment 3, the drainage test was performed with the last oil and brine
489 flow rates that were used during drainage in Experiment 2. The imbibition
490 test in Experiment 3 was started with the same initial brine saturation as
491 in Experiment 2. The phase saturations and pressure drops were verified to
492 be the same at the end of drainage in Experiments 2 and 3. The imbibition
493 test in Experiment 3 was performed by shutting down the oil pump and in-
494 creasing the water flow rate to $0.1 \text{ cm}^3/\text{min}$. Experiment 3 was performed
495 to investigate the effects of high capillary number imbibition on the residual
496 oil saturation. Oil and brine flow rates and their corresponding capillary
497 numbers in Experiment 3 are listed in Table 10.

498 In Experiment 1, the full length and cross-sectional area of the Bentheimer
499 core sample was scanned at a resolution of $2.6 \mu m$ in all directions at specified
500 steady-state points in Table 8. The Berea core sample in Experiments 2 and
501 3 was too long to be scanned at full length at every steady-state point.
502 Therefore, certain locations along the Berea core were selected as scan spots.
503 The location of these spots and their lengths and numbers are listed in Table
504 11. The Berea core in Experiments 2 and 3 was scanned at a resolution of
505 $2.49 \mu m$, in all directions, at fractional flow steps and scan spots specified in
506 Tables 9 and 10.

507 *3.2. Steady-State Criteria for Experiments*

508 During the experiments, after the brine and oil flow rates were set to their
509 predetermined values, the pressure drop along the core sample was moni-
510 tored carefully. Four differential pressure transducers with various ranges
511 were used to measure the pressure drop along the cores. When the pressure
512 drop reached a stable value, the lower resolution scanning of the core sample
513 was started. The core sample was scanned repeatedly until the saturation
514 difference between two consecutive scans was less than 1%. This would en-
515 sure the establishment of the steady-state condition. At that point, the core
516 sample was scanned with a higher resolution and the pressure drop data were
517 recorded for relative permeability calculations.

518 *3.3. Micro-CT Image Segmentation and Analysis*

519 The micro-CT images of the core samples were analyzed using the Avizo[®]
520 Fire software. A technique similar to the one used by Alizadeh et al. (2014)
521 and Khishvand et al. (2014) was used for the analysis of the micro-CT images.

522 The dry core samples were scanned to obtain reference images before the flow
523 experiments were started (see Figure 8(a)). First, the non-local means filter
524 was applied to the reference images to reduce the noise. The reference images
525 were then segmented using histogram thresholding technique as shown in
526 Figure 8 (b).

527 The analysis of the wet images obtained during the flow experiments (see
528 Figure 8(c)) was started, similar to dry images, by applying the non-local
529 means filter. Then, the wet images were registered with the dry images and
530 were multiplied by the binary pore-grain separated images to separate the
531 pore space and grains. The resulting images were then segmented for the
532 separation of the oil and brine phases (see Figure 8(d)). Arithmetic opera-
533 tions were performed on these labeled images to obtain average saturations
534 and saturation profiles along the core sample.

535 3.4. *In-Situ Contact Angle Measurements*

536 The micro-CT images obtained during the two-phase flow experiments
537 were used to measure the contact angles between the wetting and non-wetting
538 phases in the pore space. This is similar to the technique used by Andrew
539 et al. (2014). First a corner of a pore containing the brine and oil phases was
540 selected. Then the point where the brine-oil interface line intersects the solid
541 surface was detected. At that point, two lines one tangent to the solid surface
542 and the other one tangent to the brine-oil interface were drawn. The angle
543 between these two lines through the brine phase gave the brine-oil contact
544 angle at that corner. Figure 9 shows in-situ contact angle measurements in
545 pore corners in the Berea sandstone core during the experiments. Brine, oil,
546 and grains are depicted by colors blue, red, and gray, respectively. The green

lines show the tangents to the rock surface and the brine-oil interface at the triple contact points.

Table 12 lists the average, minimum, and maximum brine-oil contact angles measured at multiple points in the Bentheimer and Berea sandstone core samples during drainage and imbibition processes of Experiments 1, 2, and 3. These values were used in identifying the receding and advancing brine-oil contact angle distributions in the Bentheimer and Berea pore networks in the simulations presented here. The average, minimum, and maximum values of brine-oil contact angle distributions in the Bentheimer and Berea pore networks are also listed in Table 12 for comparison.

3.5. Fluid Phase Potential Difference

In the experiments, the core sample was placed vertically and the fluids were injected from the bottom of the core. Therefore, the effect of gravity needed to be included in the potential difference in the Darcy's equation. For this purpose, when the core sample was fully saturated with brine, the injection pumps were shut down and the pressure transducers were reset to zero. As a result, the value shown by the pressure transducers was the potential difference for the brine phase and it needed to be corrected for the oil phase relative permeability calculations.

$$\Delta\Phi_o = \Delta\Phi_b + (\rho_b - \rho_o)gL \quad (17)$$

Equation (17) was used to convert the pressure difference value read from transducers to the oil phase potential difference. In this equation, $\Delta\Phi_o$ and $\Delta\Phi_b$ are potential differences of oil and brine phases respectively, ρ_b and ρ_o

are brine and oil densities, respectively, g is the acceleration of gravity, and L is the length of the core sample. After obtaining the potential differences for each phase, the relative permeabilities were calculated using the Darcy's equation.

4. Validation

In this section, first simulation procedures and conditions, steady-state criteria for simulations, and contact angle distributions used in simulations are described. This is followed by the comparison of simulation and experimental results.

4.1. Simulation Procedures and Conditions

The dynamic model was used to perform simulations in pore networks constructed from high-resolution micro-computed tomography images of the core samples in which the experiments were performed. The properties of the pore networks representative of the Bentheimer and Berea core samples used in the experiments are presented in Tables 3 and 4, respectively. The properties of the fluids that were measured during the experiments and presented in Table 7 were used in the simulations. The simulations were performed using the same brine and oil flow rates used during the experiments. These flow rates and their corresponding capillary numbers are presented in Tables 8, 9, and 10. For each experiment listed in Table 5, there is an equivalent simulation with the same number.

The simulations were started with fully brine saturated pore networks. The vertical orientation of the core sample was simulated by using the ap-

592 appropriate coordinates of pore elements as the height in gravity pressure drop
593 calculations (see equation (5)).

594 *4.2. Steady-State Criteria for Simulations*

595 In the simulations, the pore-scale displacements were carried out in the
596 order of highest-to-lowest displacement potential (see section 2.4). The dis-
597 placements were carried out until no displacement with a positive potential
598 was left in the system. At that point, the system had reached the steady-state
599 condition for one set of inlet flow rates. The simulation and experimental
600 results are compared against each other at steady-state points.

601 *4.3. Contact Angles Used in Simulations*

602 In-situ measurements of the brine-oil contact angles during the experi-
603 ments provided us with realistic estimations of contact angle distributions
604 in the real rock pore space (see section 3.4). The average, minimum, and
605 maximum values of the random distributions of the receding and advancing
606 contact angles used in the Berea and Bentheimer pore networks are listed in
607 Table 12. One should note that the contact angles measured during drainage
608 are receding. However, the contact angles measured during imbibition are
609 either hinging or advancing and accordingly their average values are between
610 receding and advancing contact angles. Therefore, the advancing contact an-
611 gle values used in the simulations are *larger* than the contact angles measured
612 during imbibition.

613 *4.4. Comparison with Experimental Data*

614 Simulations 1, 2, and 3 were performed as the equivalents of Experiments
615 1, 2, and 3, respectively. Simulation 1 that was performed in the Bentheimer

616 sandstone network took about 15 hours to complete on 64 processors with
617 2000 MHz speed. While Simulations 2 and 3 that were performed in the Berea
618 sandstone network took about 2 weeks to complete on 200 processors with
619 2000 MHz speed. The experimental and simulation data presented here relate
620 to steady-state conditions that were established at each fractional flow point.
621 We compare each simulation with the corresponding experiment through
622 local saturation points, fractional flow curves, and relative permeabilities.

623 *4.4.1. Simulation 1*

624 In Experiment 1, the full cross section and length of the Bentheimer core
625 sample was scanned at selected fractional flow numbers listed in Table 8
626 after the steady-state condition was achieved. The scanning resolution was
627 $2.6 \mu\text{m}$ in all directions. After eliminating the micro-CT images close to the
628 inlet and outlet of the core sample that were corrupted due to geometric
629 penumbra and high noise, 4000 two-dimensional slices along the core sample
630 were obtained for each fractional flow point. These slices were then processed
631 and segmented. For brine saturation profile measurements, these 4000 slices
632 were divided into 40 groups of 100 slices. The thickness of each group of slices
633 was 0.26 mm. The volume of solid, oil, and brine phases were determined in
634 each group of slices and subsequently the brine saturation in each group was
635 calculated. The distance of the middle of each slice group from the inlet was
636 used to plot the measured brine saturation versus position along the core
637 sample. In Simulation 1, the pore network was divided into 50 partitions
638 along the length of the network. The thickness of each partition was 0.26
639 mm. The brine saturation was calculated at each fractional flow point after
640 achieving the steady-state condition. Figure 10 shows the saturation profiles

641 obtained from Experiment 1 and Simulation 1 at selected fractional flows.
642 The saturation profiles from Simulation 1 show encouraging agreement with
643 their experimental counterparts.

644 In Figure 15, fractional flows of brine versus average brine saturations ob-
645 tained from Experiment 1 and Simulation 1 are presented at each steady-state
646 point. Fractional flow curves obtained from Simulation 1 and Experiment 1
647 agree well.

648 Due to the failure of the pressure transducers during Experiment 1, the
649 pressure drop data obtained in this experiment were not useable. Here, we
650 compare the relative permeability data obtained from Simulation 1 against
651 the data available in the literature for the same rock sample. Oil-brine two-
652 phase relative permeability data on Bentheimer sandstone presented by Al-
653 izadeh and Piri (2014) and Øren et al. (1998) were used here for comparison.
654 Øren et al. (1998) used a paraffinic oil and a synthetic brine (3% NaCl),
655 while Alizadeh and Piri (2014) used Soltrol 170 and a synthetic brine (2 wt
656 % CaCl_2 , 12 wt % NaI, and 0.01 wt % NaN_3) as the non-wetting and wetting
657 phases, respectively. Øren et al. (1998) reported the experiments at ambient
658 pressure and temperature, while Alizadeh and Piri (2014) performed their
659 experiments at 5.52 MPa and ambient temperature. They present drainage
660 and imbibition relative permeabilities versus brine saturation. Figure 12
661 shows the relative permeabilities obtained from Simulation 1 and the liter-
662 ature data on drainage and imbibition. As it is apparent from this figure,
663 the relative permeabilities from Simulation 1 are in good agreement with the
664 experimental values from the literature. The predicted residual oil saturation
665 also matches the experimental values.

666 *4.4.2. Simulation 2*

667 In Experiment 2, the middle section of the Berea core sample was scanned
668 in all fractional flows. The bottom and top parts of the core were scanned
669 in selected fractional flows (see Table 9). The scanning resolution was 2.49
670 μm in all directions.

671 The brine saturation profiles in the bottom, middle, and top sections of
672 the medium at the end of first drainage and last imbibition fractional flows
673 obtained from Experiment 2 and Simulation 2 are presented in Figure 13.
674 The experimental data points in this figure are obtained by dividing the 2D
675 micro-CT slices into 60 groups of 30 slices. The thickness of each group was
676 74.7 μm . The simulation data are obtained by dividing the pore network into
677 60 partitions in the same middle, bottom, and top sections of the medium
678 as Experiment 2, and calculating the brine saturation in each partitions.

679 Figure 14 shows saturation profiles in full length of the medium obtained
680 from Simulation 2. Experiment 2 results are also depicted in this figure in
681 locations where the core sample was scanned. Each data point in this figure
682 represents the saturation in a 0.747 mm long section of the medium.

683 As seen in Figures 13 and 14, the saturation profiles from Simulation
684 2 compare well with those from Experiment 2. Since this experiment was
685 performed under capillary-dominated displacement regime, the saturation
686 profiles are uniform along the length of the sample, a condition that is crit-
687 ical for steady-state relative permeability measurements (Alizadeh and Piri,
688 2014).

689 Fractional flows of brine versus saturation obtained from Experiment 2
690 and Simulation 2 at each steady-state point are presented in Fig 15. The frac-

691 tional flow curves show good agreement between the measured and predicted
692 data.

693 Relative permeabilities from Simulation 2 are compared against relative
694 permeabilites from Experiment 2 and the data available in the literature. The
695 experimental oil-brine two-phase relative permeability data on Berea sand-
696 stone presented by Oak (1990) are used for comparison purposes. Oak (1990)
697 performed the two-phase experiments with brine (5% NaCl, 0.5% CaCl₂) and
698 dodecane at 5.52 MPa and ambient temperature conditions. Figure 16 shows
699 the relative permeabilities from Simulation 2, Experiment 2, and Oak (1990).
700 In this figure, brine saturation of Experiment 2 is obtained from the mid-
701 dle section of the core sample. As shown in this figure, Simulation 2 and
702 Experiment 2 relative permeability and saturation values show good agree-
703 ment. Simulation 2 and Experiment 2 data show a slight discrepancy with
704 the data from Oak (1990), which may be attributed to the differences in the
705 samples used. For instance, the absolute permeabilities of the samples used
706 by Oak (1990) were 200 mD, 800 mD, and 1000 mD while our sample had
707 an absolute permeability of 623 mD. Furthermore, the core samples used by
708 Oak (1990) were fired before performing the flow experiments. It is note-
709 worthy that in the quasi-static pore network models that have been used to
710 match the data from Oak (1990) the pore networks have higher porosity and
711 clay content than the Berea sandstone network used in this work (see, for
712 instance, Lerdahl et al. (2000); Piri and Blunt (2005a,b)).

713 4.4.3. *Simulation 3*

714 In Experiment 3, the middle, bottom, and top sections of the Berea core
715 sample were scanned at a resolution of 2.49 μm (in all directions) at all imbi-

716 bition fractional flows. The drainage part of this experiment was performed
 717 to establish the same initial brine saturation as in Experiment 2. This was
 718 confirmed by a lower resolution scan at the end of drainage. The middle,
 719 top, and bottom section micro-CT images obtained at the end of imbibition
 720 fractional flows were analyzed and grouped using the same approach as Ex-
 721 periment 2. Figure 17 shows saturation profiles in full length of the medium
 722 obtained from Simulation 3 and Experiment 3. Each data point in this fig-
 723 ure represents the saturation in a 0.747 mm long section of the medium.
 724 Simulation 3 saturation profiles are in good agreement with their experimen-
 725 tal counterparts. Due to the dynamic effects caused by the higher capillary
 726 number during imbibition (see Table 10), in Experiment 3 and Simulation 3,
 727 there is a slight difference between brine saturation in the bottom, middle,
 728 and top sections of the medium. The predicted residual oil saturation agrees
 729 closely with the experimental value.

730 **5. Simulation of Different Processes**

731 Having rigorously validated the dynamic model against the experimental
 732 data, in this section, we use it to study other processes. Three simulations
 733 were conducted in the Bentheimer sandstone network introduced earlier. All
 734 three simulations were performed with the brine and oil flow rates used in
 735 Simulation 1 (see Table 8). However, different IFT and viscosity values were
 736 used in each simulation. Following the simulation numbering used in the
 737 previous section, simulations in this section are numbered 4, 5, and 6. Prop-
 738 erties of the fluids and ranges of the capillary number in Simulations 4, 5, and
 739 6 are listed in Table 13. The contact angle distributions used in Simulation

1 (see Table 12) were used in Simulations 4, 5, and 6. The simulation results in this section are compared against the results from Simulation 1 with the purpose of investigating the effects of low IFT and high viscosity of wetting phase on relative permeabilities, residual oil saturation, and fractional flow curves.

5.1. Simulation 4 - Surfactant Flooding

Surfactant flooding is an enhanced oil recovery technique that is used to increase recovery by reducing IFT between displacing phase and oil. By lowering IFT the capillary forces that are responsible for trapping oil in the pore scale are reduced and the effect of viscous forces becomes significant (Lake, 1989; Green and Willhite, 1998). Simulation 4 was performed in order to investigate how a low IFT value might affect relative permeabilities and residual oil saturation. The IFT value in this simulation was 1.0 mN/m as opposed to 46.34 mN/m in Simulation 1 (see Tables 7 and 13). Due to the reduced IFT value, the capillary numbers in Simulation 4 are higher than those in Simulation 1 and they range between 3×10^{-6} and 1×10^{-3} (see Tables 8 and 13).

As seen in Figure 18, relative permeabilities of wetting and non-wetting phases in Simulation 4 are higher than those in Simulation 1 for a given saturation. Furthermore, a wider range of saturation is observed during drainage and imbibition in Simulation 4. Residual oil saturation in this simulation is 21.36 %, which is 15.75 % lower than that in Simulation 1 with a higher IFT.

In Simulation 4, due to the low IFT value used, the capillary pressure drop associated with pore-scale displacements becomes lower and the viscous

765 pressure drop becomes a more significant term in the displacement pressure
766 drop (see section 2.4). Therefore, pore-scale displacements take place in paths
767 that result in lower viscous pressure drop. These flow paths can conduct the
768 same flow rate with lower viscous pressure drop. In other words, there is less
769 resistance in these flow paths. For this reason, higher relative permeabilities
770 are obtained in Simulation 4 for a given saturation.

771 In this simulation, the rise in the capillary number makes the effect of vis-
772 cous pressure drop more dominant. Therefore, the pore-scale displacements
773 that are closer to the displacement front become more favorable. Conse-
774 quently, piston-like displacements close to the displacement front are favored
775 over snap-off displacements ahead of the front. This change in the favored
776 displacement type results in less trapping of the non-wetting phase. There-
777 fore, in this simulation residual oil saturation is lower than that in Simulation
778 1.

779 5.2. Simulation 5 - Polymer Flooding

780 Polymer flooding is an enhanced oil recovery technique in which polymer
781 is added to the displacing phase in order to decrease its mobility and increase
782 the sweep efficiency of the flooding process. The added polymer decreases
783 the mobility of the displacing phase by increasing its viscosity, and, in some
784 cases, by decreasing its permeability. It is generally believed that adding
785 polymer by itself does not decrease the residual oil saturation if the capillary
786 number is kept constant (Lake, 1989). However, in this section, we compare
787 two cases with the same flow rates but different viscosities and, therefore,
788 different capillary numbers. The effects that are seen in this simulation are
789 the result of an increase in the capillary number. In this simulation, the

viscosity ratio of the wetting to non-wetting phase was 5.0 as opposed to 1.31 in Simulation 1 (see Tables 7 and 13). Due to the increase in viscosity of the wetting phase, the capillary numbers during imbibition in Simulation 5 are higher than those in Simulation 1 and they range between 8×10^{-7} and 8×10^{-5} (see Tables 8 and 13).

In Figure 19(a) drainage relative permeabilities obtained from Simulations 5 and 1 are compared. Since the capillary number during drainage is almost the same in these two simulations, drainage relative permeabilities do not show a significant difference. However, drainage steady-state points in Simulation 5 are established at lower wetting-phase saturations than those in Simulation 1 for a given fractional flow. This can be attributed to the fact that the higher viscosity of the wetting phase in Simulation 5 increases the viscous pressure drop of the wetting phase and makes it more difficult for oil to displace the wetting phase with the same flow rates as in Simulation 1.

As seen in 19(b), wetting-phase relative permeability does not show a big difference in Simulations 5 and 1. Oil relative permeability, however, is greater in Simulation 5 for a given saturation. Furthermore, the residual oil saturation in Simulation 5 is 24.10%, which is 13.01% lower than residual oil saturation in Simulation 1. Because of the higher wetting-phase-to-oil viscosity ratio in Simulation 5, the flow pattern becomes more stable during imbibition (Lenormand et al., 1988), meaning that the wetting-phase-to-oil displacements closer to the inlet are favored. Therefore, piston-like displacements closer to the inlet are favored over snap-off displacements ahead of the displacement front. The change in the flow pattern results in less trapping of oil. Therefore, oil relative permeability is higher and residual oil saturation

815 is lower in Simulation 5.

816 5.3. Simulation 6 - Surfactant-Polymer Flooding

817 Polymers are sometimes used in surfactant flooding in order to increase
818 the sweep efficiency of the process by lowering the mobility of the displacing
819 phase (Lake, 1989). Simulation 6 was performed to study the combined effect
820 of low IFT and high viscosity of the wetting phase on relative permeabilities
821 and residual oil saturation. Due to the low IFT value and high viscosity
822 of the wetting-phase, the capillary numbers in Simulation 6 are higher than
823 those in Simulations 1, 4, and 5 and they range between 4×10^{-6} and 4×10^{-3}
824 (see Tables 8 and 13).

825 As shown in Figure 20(a), the dynamic effects observed during drainage
826 in Simulation 4 are present and more significant in Simulation 6. Saturation
827 ranges in Simulations 4 and 6 are almost identical during drainage. However,
828 steady-state points are established at different saturations in these simula-
829 tions for a given fractional flow. Wetting-phase relative permeability is higher
830 in Simulation 6 for a given saturation. Oil relative permeability is higher in
831 early stages and then it becomes lower in late drainage.

832 Because in Simulation 6 viscosity ratio of wetting phase to oil is 5.0,
833 during drainage, oil has an unstable front (Lenormand et al., 1988). The
834 low IFT value and the high viscosity of the wetting phase in this simulation
835 makes the wetting-phase viscous pressure drop the dominant force in dis-
836 placements. Therefore, oil-to-wetting-phase displacements that are closer to
837 the outlet are preferred. In other words, displacements tend to take place in
838 the paths that cause the least wetting-phase viscous pressure drop. However,
839 these displacement paths do not necessarily have the least resistance to oil.

840 Furthermore, there may be some un-swept banks of water that would cause
841 more viscous pressure drop in oil flow. Additionally, the high viscosity of the
842 wetting phase increases the wetting-phase pressure in the corners and keeps
843 the wetting layers thick in Simulation 6. Because of the above-mentioned
844 reasons, drainage wetting-phase relative permeability is higher in Simulation
845 6 than its counterpart in Simulation 4; and drainage oil relative permeability
846 becomes lower especially during late stages in Simulation 6.

847 In imbibition, the dynamic effects that caused an increase in relative
848 permeabilities in Simulation 4 are seen in Simulation 6, as well (see Figure
849 20(b)). Wetting-phase relative permeabilities from Simulations 4 and 6 are
850 almost identical. Oil relative permeabilities from Simulation 6, however,
851 are a little higher than their counterparts from Simulation 4. Residual oil
852 saturation in Simulation 6 is 17.27%, which is 4.09% and 19.84 % lower than
853 residual oil saturations in Simulations 1 and 4, respectively.

854 In Simulation 6, since the wetting-phase-to-oil viscosity ratio is 5.0, the
855 displacement front during imbibition is stable (Lenormand et al., 1988). The
856 dominant force in displacements is the viscous pressure drop of the wetting
857 phase. Therefore, there is less trapping of oil in this simulation compared to
858 Simulation 4 in which wetting-phase-to-oil viscosity ratio is 1.31. This shows
859 that adding a polymer to a surfactant solution can increase the oil recovery
860 by reducing the mobility of the displacing phase and consequently changing
861 the flow pattern and inhibiting the snap-off displacements.

862 Fractional flow curves of wetting-phase obtained from Simulations 1, 4,
863 5, and 6 during drainage and imbibition are shown in Figure 21. As seen in
864 Figure 21(a), the lowest wetting-phase saturation during drainage is obtained

in Simulations 4 and 6, in which the IFT value is 1.0 mN/m. In imbibition, as seen in Figure 21(b), the lowest residual saturation is obtained from Simulation 6, where the IFT value and wetting-phase-to-oil viscosity ratio are 1.0 mN/m and 5.0, respectively. Following Simulation 6, Simulations 4 and 5 have the second and third lowest residual oil saturations, respectively.

In order to evaluate the validity of the dynamic behavior observed in Simulations 4, 5, and 6, here, we briefly discuss the experimental observations reported in the literature for high capillary number flows. du Prey (1973) conducted two-phase flow experiments in artificial porous media in order to study the parameters affecting relative permeabilities and residual saturations. It was shown that higher capillary numbers result in higher relative permeabilities. Furthermore, the viscosity ratio was shown to affect relative permeabilities and the displacement pattern. Amaefule and Handy (1982) studied the effect of IFT on relative permeabilities using core-flooding tests in Berea samples. Oil and water relative permeabilities increased with decreasing IFT. The residual oil saturation was shown to decrease by lowering IFT at high capillary numbers. Chatzis and Morrow (1984) conducted core-flooding experiments in water-wet sandstones to investigate the displacement of initially continuous and residual oil with the increase in the capillary number. The decrease in residual saturation of initially continuous oil started at capillary numbers lower than 10^{-5} . The rise in relative permeabilities and the decrease in residual oil saturation by increasing the capillary number, that are observed in Simulations 4, 5, and 6 of the present work, are consistent with the experimental results reported in the above-mentioned studies. Lenormand et al. (1988) studied two-phase flow in porous media in a wide range of

capillary numbers and viscosity ratios using a dynamic pore network model and micromodel tests. Stable displacement, viscous fingering, and capillary fingering flow patterns were identified in the results from simulations and experiments. The higher viscosity ratio of the displacing to displaced phase at high capillary numbers was shown to produce a stable displacement front and reduce the trapping of non-wetting phase in imbibition. On the other hand, the lower viscosity ratio of the displacing to displaced phase at high capillary numbers was shown to generate viscous fingers of the displacing phase across the medium. Toussaint et al. (2012) discussed the flow patterns observed during drainage experiments in disordered porous media. The relative permeabilities and residual oil saturations obtained from Simulations 4, 5, and 6, in the present work, reflect the displacement patterns that are in agreement with the results reported in the literature (Lenormand et al., 1988; Toussaint et al., 2012).

The effects of IFT, viscosity ratio, and capillary number on displacement pattern, relative permeabilities, and residual saturations that are observed in Simulations 4, 5, and 6 show some of the capabilities of our dynamic model. This model can also be used to study size effects and obtain quantitative scaling laws by running simulations on networks with different sizes and keeping all the other simulation parameters the same. Furthermore, the effects of micro-fractures, pore-space heterogeneities, and different pore types in carbonate rocks on two-phase flow properties can be studied using this model. Quasi-static models, which do not include viscous and gravitational forces, and majority of the previously-developed dynamic models, which run on small networks of a few hundred to a few thousand pores, cannot be used

915 to study the above-mentioned phenomena.

916 6. Conclusions

917 A new dynamic pore network model that is capable of simulating flow at
918 the core scale was developed. This dynamic pore network model can be used
919 as a platform to study various two-phase flow processes in porous media. The
920 dynamic model included six critical elements: (1) the pressure drops associ-
921 ated with capillary, viscous, and gravity forces, (2) wetting-phase corner flow,
922 (3) corner interface adjustments based on changes in local capillary pressure,
923 (4) simultaneous injection of wetting and non-wetting phases from the inlet
924 of the medium at constant flow rates, (5) parallelization based on a three-
925 dimensional domain decomposition scheme that made simulations on large
926 core-size samples possible, and (6) constant pressure boundary condition at
927 the outlet. These features make the model, to the best of our knowledge, the
928 first of its kind that can be used to bridge the gap between pore and core
929 scales for a wide range of flow problems in different conventional rock types.

930 For the validation of the dynamic model, three two-phase miniature flow
931 experiments were performed using a state-of-the-art micro core-flooding ap-
932 paratus that is integrated with a high-resolution micro-CT scanner. A Ben-
933 theimer sandstone core with the length of 12.98 mm and the diameter of 4.97
934 mm, and a Berea sandstone core with the length of 76.40 mm and the diam-
935 eter of 4.58 mm were used in the experiments. The dynamic model was used
936 to perform simulations with the identical medium size, flow rates, and fluid
937 properties as the experiments in the pore networks that were constructed
938 from high-resolution micro-CT images of the core samples. The micro-CT

939 images obtained from the two-phase flow experiments were used to obtain in-
940 situ brine-oil contact angles during various stages of the experiments. These
941 measurements were then used to design realistic contact angle distributions
942 in the pore networks for the simulations.

943 The predicted saturation profiles, fractional flow curves, relative perme-
944 abilities, and residual oil saturations compared successfully against their ex-
945 perimental counterparts. Furthermore, the relative permeabilities and resid-
946 ual oil saturations from simulations and experiments were consistent with
947 the data available in the literature. The encouraging agreement between the
948 measured results and the predicted results is the manifestation of the rele-
949 vant two-phase flow physics along with the realistic boundary conditions and
950 fluid and rock properties used in the model. This makes the pore network
951 model introduced in this work a powerful platform for studying complex dy-
952 namic two-phase flow processes in porous media in core-size rock samples.
953 Moreover, this dynamic model can be used for coupling with continuum-scale
954 reservoir simulators.

955 The validated model was used to simulate low-IFT and high-viscosity
956 two-phase flow processes that occur in, for instance, many enhance oil recov-
957 ery schemes. Three simulations with different IFT values and viscosity ratios
958 were performed to study the effects of high capillary number on relative per-
959 meabilities and residual oil saturation. The relative permeabilities increased
960 with the rise of the capillary number. The residual oil saturation decreased
961 as the flow pattern became more viscous dominated. The lowest residual
962 oil saturation was obtained in the case where the viscosity ratio of the wet-
963 ting phase to oil was the highest and the IFT value was the lowest. The

964 dynamic effects observed during the high capillary number simulations were
965 in agreement with the results reported from microfluidics and core-flooding
966 tests available in the literature.

967 **Acknowledgments**

968 This work was supported by DOE Financial Assistance Agreement DE-
969 FE0004832. We also acknowledge the financial support of Hess Corpora-
970 tion and the School of Energy Resources at the University of Wyoming.
971 We extend our gratitude to Hu Dong and Sven Roth of iRock Technologies
972 for generating the pore networks for our samples. We also thank Mahdi
973 Khishvand, Henry Plancher, Morteza Akbarabadi, and Soheil Saraji of Piri
974 Research Group at the University of Wyoming for their help with the exper-
975 iments and laboratory measurements. All the data presented in this work
976 can be obtained from Dr. Mohammad Piri of the University of Wyoming
977 (mpiri@uwyo.edu).

978 **References**

- 979 Aghaei, A., 2014. Direct pore-to-core up-scaling of displacement processes:
980 Experimentation and dynamic pore network modeling. PhD dissertation,
981 University of Wyoming, Laramie, WY, USA.
- 982 Aker, E., Maløy, K. J., Hansen, A., Batrouni, G. G., 1998. A two-dimensional
983 network simulator for two-phase flow in porous media. *Transport in Porous*
984 *Media* **32**(2), 163–186.

- 985 Al-Gharbi, M. S., Blunt, M. J., 2005. Dynamic modeling of two-phase
986 drainage in porous media. *Physical Review E* **71**(016308), 016308–1–
987 016308–16.
- 988 Alizadeh, A. H., Khishvand, M., Ioannidis, M. A., Piri, M., 2014. Multi-scale
989 experimental study of carbonated water injection: An effective process for
990 mobilization and recovery of trapped oil. *Fuel* 132, 21917235.
- 991 Alizadeh, A. H., Piri, M., 2014. The effect of saturation history on three-
992 phase relative permeability: An experimental study. *Water Resources Re-*
993 *search* 50.
- 994 Amaefule, J. O., Handy, L. L., 1982. The effect of interfacial tensions on rel-
995 ative oil/water permeabilities of consolidated porous media. *SPE Journal*
996 22, 371–381.
- 997 Amestoy, P. R., Guermouche, A., L’Excellent, J.-Y., Pralet, S., 2006. Hybrid
998 scheduling for the parallel solution of linear systems. *Parallel Computing*
999 **32**(2), 136–156.
- 1000 Amestoy, P. R., I. S. Duff, J. K., L’Excellent, J.-Y., 2001. A fully asyn-
1001 chronous multifrontal solver using distributed dynamic scheduling. *SIAM*
1002 *Journal of Matrix Analysis and Applications* **23**(1), 15–41.
- 1003 Andrew, M., Bijeljic, B., Blunt, M. J., 2014. Pore-scale contact angle mea-
1004 surements at reservoir conditions using x-ray microtomography. *Advances*
1005 *in Water Resources* 68, 24–31.
- 1006 Blunt, M. J., Jackson, M. D., Piri, M., Valvatne, P. H., 2002. Detailed

1007 physics, predictive capabilities and macroscopic consequences for pore-
1008 network models of multiphase flow. *Advances in Water Resources* **25**(8-12),
1009 1069–1089.

1010 Blunt, M. J., King, P., 1991. Relative permeabilities from two- and three-
1011 dimensional pore-scale network modelling. *Transport in Porous Media*
1012 **6**(4), 407–433.

1013 Chatzis, I., Morrow, N. R., 1984. Correlation of capillary number relation-
1014 ships for sandstone. *SPE Journal* 24.

1015 Constantinides, G. N., Payatakes, A. C., 2000. Effects of precursor wet-
1016 ting films in immiscible displacement through porous media. *Transport*
1017 *in Porous Media* **38**(3), 291–317.

1018 Dahle, H. K., Celia, M. A., 1999. A dynamic network model for two-phase
1019 immiscible flow. *Computational Geosciences* **3**(1), 1–22.

1020 DiCarlo, D. A., 2004. Experimental measurements of saturation overshoot
1021 on infiltration. *Water Resources Research* 40.

1022 DiCarlo, D. A., 2006. Quantitative network model predictions of saturation
1023 behind infiltration fronts and comparison with experiments. *Water Re-*
1024 *sources Research* 42.

1025 Dong, H., Blunt, M. J., 2009. Pore-network extraction from micro-
1026 computerized-tomography images. *Physcial Review E* 80, 036307.

1027 du Prey, E. J. L., 1973. Factors affecting liquid-liquid relative permeabilities
1028 of a consolidated porous medium. *SPE Journal* 13, 39–47.

- 1029 Dullien, F. A. L., 1992. Porous Media: Fluid Transport and Pore Structure,
1030 2nd Edition. Academic Press, San Diego.
- 1031 Fatt, I., 1956a. The network model of porous media I. Capillary pressure
1032 characteristics. Transactions of the American Institute of Mining, Metal-
1033 lurgical, and Petroleum Engineers **207**, 144–159.
- 1034 Fatt, I., 1956b. The network model of porous media II. Dynamic properties
1035 of a single size tube network. Transactions of the American Institute of
1036 Mining, Metallurgical, and Petroleum Engineers **207**, 160–163.
- 1037 Fatt, I., 1956c. The network model of porous media III. Dynamic properties
1038 of networks with tube radius distribution. Transactions of the American
1039 Institute of Mining, Metallurgical, and Petroleum Engineers **207**, 164–181.
- 1040 Fourie, W., Said, R., Young, P., Barnes, D., 2007. The simulation of pore
1041 scale fluid flow with real world geometries obtained from X-ray computed
1042 tomography. Proceedings of the COMSOL Conference, Boston.
- 1043 Gabriel, E., Fagg, G. E., Bosilca, G., Angskun, T., Dongarra, J. J., Squyres,
1044 J. M., Sahay, V., Kambadur, P., Barrett, B., Lumsdaine, A., Castain,
1045 R. H., Daniel, D. J., Graham, R. L., Woodall, T. S., September 2004. Open
1046 MPI: Goals, concept, and design of a next generation MPI implementa-
1047 tion. In: Proceedings, 11th European PVM/MPI Users’ Group Meeting.
1048 Budapest, Hungary, pp. 97–104.
- 1049 Gingold, R., Monaghan, J., 1997. Smoothed particle hydrodynamics: the-
1050 ory and application to non-spherical stars. Monthly Notices of the Royal
1051 Astronomical Society 181, 37517389.

- 1052 Green, D. W., Willhite, G. P., 1998. Enhanced Oil Recovery, 1st Edition.
1053 SPE, Richardson, TX.
- 1054 Hashemi, M., Dabir, B., Sahimi, M., 1999a. Dynamics of two-phase flow in
1055 porous media: Simultaneous invasion of two fluids. *AIChE Journal* 45,
1056 1365.
- 1057 Hashemi, M., Sahimi, M., Dabir, B., 1998. Percolation with two invaders and
1058 two defenders: Volatile clusters, oscillations, and scaling. *Physical Review*
1059 *Letters* 80, 3248.
- 1060 Hashemi, M., Sahimi, M., Dabir, B., 1999b. Monte Carlo simulation of two-
1061 phase flow in porous media: Invasion with two invaders and two defenders.
1062 *Physica A* 267, 1.
- 1063 Hassanizadeh, S. M., Gray, W. G., 1990. Mechanics and thermodynamics
1064 of multiphase flow in porous media including interphase boundaries. *Ad-*
1065 *vances in Water Resources* 13, 169–186.
- 1066 Hughes, R. G., Blunt, M. J., 2000. Pore scale modeling of rate effects in
1067 imbibition. *Transport in Porous Media* **40**(3), 295–322.
- 1068 Hui, M. H., Blunt, M. J., 2000. Effects of wettability on three-phase flow in
1069 porous media. *Journal of Physical Chemistry B* **104**(16), 3833–3845.
- 1070 Inamuro, T., Ogata, T., Tajima, S., Konishi, N., 2004. A Lattice Boltzmann
1071 method for incompressible two-phase flows with large density differences.
1072 *Journal of Computational Physics* 198, 628644.

- 1073 Joekear-Niasar, V., Hassanizadeh, S. M., 2012. Analysis of fundamentals of
1074 two-phase flow in porous media using dynamic pore-network models: A
1075 review. *Critical Reviews in Environmental Science and Technology* 42:18,
1076 1895–1976.
- 1077 Joekear-Niasar, V., Hassanizadeh, S. M., Dahle, H. K., 2010. Non-equilibrium
1078 effects in capillarity and interfacial area in two-phase flow: Dynamic pore-
1079 network modelling. *Journal of Fluid Mechanics* 655.
- 1080 Kamath, J., Xu, B., Lee, S., Yortsos, Y., 1996. Pore network modeling of lab-
1081 oratory experiments on heterogeneous carbonates. Paper SPE 36681, Pro-
1082 ceedings of the SPE Annual Technical Conference and Exhibition, Denver,
1083 Colorado, 6-9 October.
- 1084 Karpyn, Z. T., Piri, M., 2007. Prediction of fluid occupancy in fractures us-
1085 ing network modeling and X-ray microtomography. I: Data conditioning
1086 and model description. *Physical Review E* **76**(016315), doi: 10.1103/Phys-
1087 RevE.76.016315.
- 1088 Khishvand, M., Akbarabadi, M., Piri, M., 2014. A pore-level investigation
1089 of residual trapping, dynamic effects, and matrix dissolution in sandstone
1090 and carbonate using x-ray microtomography. submitted to *Microporous*
1091 *and Mesoporous Materials*.
- 1092 Knudsen, H. A., Hansen, A., 2002. Relation between pressure and fractional
1093 flow in two-phase flow in porous media. *Physical Review E* **65**(5).
- 1094 Koplik, J., Lasseter, T., 1985. Two-phase flow in random network models of
1095 porous media. *SPE Journal* 25.

- 1096 Koshizuka, S., Tamako, H., Oka, Y., 1995. A particle method for incompress-
1097 ible viscous flow with fluid fragmentation. *Computational Fluid Dynamics*
1098 *Journal* **4**(1), 291-746.
- 1099 Lake, L. W., 1989. *Enhanced Oil Recovery*, 1st Edition. Prentice Hall, En-
1100 glewood Cliffs, NJ.
- 1101 Lee, S. H., Padmanabhan, L., Al-Sunaidi, H. A., 1995. Simulation of lin-
1102 ear displacement experiments on massively parallel computers. Paper SPE
1103 30721, *Proceedings of the SPE Annual Technical Conference and Exhibi-*
1104 *tion*, Dallas, TX, 22-25 October.
- 1105 Lenormand, R., Touboul, E., Zarcone, C., 1988. Numerical models and ex-
1106 periments on immiscible displacements in porous media. *Journal of Fluid*
1107 *Mechanics* **189**(April), 165–187.
- 1108 Lerdahl, T. R., Øren, P. E., Bakke, S., 2000. A predictive network model for
1109 three-phase flow in porous media. Paper SPE 59311, *Proceedings of the*
1110 *SPE/DOE Symposium in Improved Oil Recovery*, Tulsa, Oklahoma, 3-5
1111 April.
- 1112 Li, H., Pan, C., Miller, C., 2005. Pore-scale investigation of viscous coupling
1113 effects for two-phase flow in porous media. *Physical Review E* **72**, 026705.
- 1114 Løvoll, G., Méheust, Y., Måløy, K. J., Aker, E., Schmittbuhl, J., 2005. Com-
1115 petition of gravity, capillary and viscous forces during drainage in a two-
1116 dimensional porous medium, a pore scale study. *Energy* **30**, 861–872.

- 1117 Mayer, R. P., Stowe, R. A., 1965. Mercury porosimetry-breakthrough pres-
 1118 sure for penetration between packed spheres. *Journal of Colloid Science*
 1119 **20**, 893–911.
- 1120 Mogensen, K., Stenby, E., 1998. A dynamic two-phase pore-scale model of
 1121 imbibition. *Transport in Porous Media* 32.
- 1122 Nguyen, V. H., Sheppard, A. P., Knackstedt, M. A., Pinczewski, W. V.,
 1123 2006. The effect of displacement rate on imbibition relative permeability
 1124 and residual saturation. *Journal of Petroleum Science and Engineering* 52.
- 1125 Nordhaug, H. F., Celia, M., Dahle, H. K., 2003. A pore network model for
 1126 calculation of interfacial velocities. *Advances in Water Resources* **26**(10),
 1127 1061–1074.
- 1128 Oak, M. J., 1990. Three-phase relative permeability of water-wet Berea. Pa-
 1129 per SPE 20183, Proceedings of the SPE/DOE Seventh Symposium on
 1130 Enhanced Oil Recovery, Tulsa, Oklahoma, 22-25 April.
- 1131 Øren, P. E., Bakke, S., 2003. Reconstruction of berea sandstone and pore-
 1132 scale modelling of wettability effects. *Journal of Petroleum Science and*
 1133 *Engineering* 39, 177–199.
- 1134 Øren, P. E., Bakke, S., Arntzen, O. J., 1998. Extending predictive capabilities
 1135 to network models. *SPE Journal* **3**(4), 324–336.
- 1136 Ovaysi, S., Piri, M., 2010. Direct pore-level modeling of incompressible fluid
 1137 flow in porous media. *Journal of Computational Physics* 229, 7456177476.

- 1138 Ovaysi, S., Piri, M., 2011. Pore-scale modeling of dispersion in disordered
1139 porous media. *Journal of Contaminant Hydrology* 124, 68–81.
- 1140 Patzek, T. W., 2001. Verification of a complete pore network simulator of
1141 drainage and imbibition. *SPE Journal* **6**(2), 144–156.
- 1142 Patzek, T. W., Silin, D. B., 2001. Shape factor and hydraulic conductance in
1143 noncircular capillaries. I. One-phase creeping flow. *Journal of Colloid and*
1144 *Interface Science* **236**(2), 295–304.
- 1145 Piri, M., Blunt, M. J., 2005a. Three-dimensional mixed-wet ran-
1146 dom pore-scale network modeling of two- and three-phase flow in
1147 porous media. I. Model description. *Physical Review E* **71**(026301),
1148 doi:10.1103/PhysRevE.71.026301.
- 1149 Piri, M., Blunt, M. J., 2005b. Three-dimensional mixed-wet random pore-
1150 scale network modeling of two- and three-phase flow in porous media. II.
1151 Results. *Physical Review E* **71**(026302), doi:10.1103/PhysRevE.71.026302.
- 1152 Piri, M., Karpyn, Z. T., 2007. Prediction of fluid occupancy in fractures
1153 using network modeling and X-ray microtomography. II: Results. *Physical*
1154 *Review E* **76**(016316), doi: 10.1103/PhysRevE.76.016316.
- 1155 Premože, S., Tasdizen, T., Bigler, J., Lefohn, A., Whitaker, R., 2003.
1156 Particle-based simulation of fluids. *Computer Graphics Forum* 22, 3.
- 1157 Princen, H. M., 1969a. Capillary phenomena in assemblies of parallel cylin-
1158 ders I. Capillary rise between two cylinders. *Journal of Colloid and Inter-*
1159 *face Science* **30**(1), 69–75.

- 1160 Princen, H. M., 1969b. Capillary phenomena in assemblies of parallel cylin-
1161 ders II. Capillary rise in systems with more than two cylinders. Journal of
1162 Colloid and Interface Science **30**(3), 359–371.
- 1163 Princen, H. M., 1970. Capillary phenomena in assemblies of parallel cylin-
1164 ders III. Liquid columns between horizontal parallel cylinders. Journal of
1165 Colloid and Interface Science **34**(2), 171–184.
- 1166 Sahimi, M., 2010. Flow and Transport in Porous Media and Fractured Rock,
1167 2nd Edition. Wiley-VCH, Los Angeles.
- 1168 Saraji, S., Goual, L., Piri, M., 2013. Wettability of sc-CO₂/water/Quartz sys-
1169 tems: Simultaneous measurement of contact angle and interfacial tension
1170 at reservoir conditions. Langmuir 29, 6856–6866.
- 1171 Schaefer, C. E., DiCarlo, D. A., Blunt, M. J., 2000. Experimental measure-
1172 ment of air-water interfacial area during gravity drainage and secondary
1173 imbibition in porous media. Water Resources Research **36**(4), 885–890.
- 1174 Sheng, Q., Thompson, K., 2013. Dynamic coupling of pore-scale and
1175 reservoir-scale models for multiphase flow. Water Resources Research 49.
- 1176 Singh, M., Mohanty, K. K., 2003. Dynamic modeling of drainage through
1177 three-dimensional porous material. Chemical Engineering Science **58**, 1–
1178 18.
- 1179 Stauffer, F., 1978. Time dependence of the relations between capillary pres-
1180 sure, water content and conductivity during drainage of porous media.
1181 IAHR Symposium on Scale Effects in Porous Media, Thessaloniki, Greece,
1182 3.35–3.52.

- 1183 Tartakovsky, A., Meakin, P., 2005. A smoothed particle hydrodynamics for
1184 miscible flow in three-dimensional fractures and two-dimensional Rayleigh-
1185 Taylor instability. *Journal of Computational Physics* 207, 61017624.
- 1186 Thompson, K. E., 2002. Pore-scale modeling of fluid transport in disordered
1187 fibrous materials. *AIChE Journal* 48(7).
- 1188 Tørå, G., Øren, P.-E., Hansen, A., 2012. A dynamic network model for two-
1189 phase flow in porous media. *Transport in Porous Media* 92, 145–164.
- 1190 Toussaint, R., Måløy, K. J., Méheust, Y., Løvoll, G., Jankov, M., Schäfer, G.,
1191 Schmittbuhl, J., 2012. Two-phase flow: Structure, upscaling, and conse-
1192 quences for macroscopic transport properties. *Vadose Zone Journal* 11(3),
1193 doi=10.2136/vzj2011.0123.
- 1194 Valvatne, P. H., Blunt, M. J., 2004. Predictive pore-scale modeling of two-
1195 phase flow in mixed wet media. *Water Resources Research* 40, W07406.
- 1196 van der Marck, S. C., Matsuura, T., Glas, J., 1997. Viscous and capillary
1197 pressures during drainage: Network simulations and experiments. *Physical*
1198 *Review E* **56**(5), 5675–5687.
- 1199 Xu, B., Kamath, J., Yortsos, Y., Lee, S., 1999. Use of pore-network models to
1200 simulate laboratory corefloods in a heterogeneous carbonate sample. *SPE*
1201 *Journal* 4(3), 179–186.
- 1202 Zhu, Y., Fox, P. J., Morris, J. P., 1999. A pore-scale numerical model for flow
1203 through porous media. *International Journal for Numerical and Analytical*
1204 *Methods in Geomechanics* 23, 88117904.

Figure 1: Pore network representation of the Berea sandstone core sample. (a) Volume rendered gray-scale images of the Berea core sample scanned with a micro-CT scanner at a resolution of $2.49 \mu\text{m}$. (b) Volume rendered pore-grain separated images of the Berea core sample. Red and gray colors represent the pore and grain voxels, respectively. (c) Pore network generated from images (a) and (b). Red and blue colors represent the pores and throats in the network, respectively. For illustrative purposes pores and throats are shown with circular cross-section here. (d) A magnified image of a small section of the Berea pore network.

Figure 2: All possible fluid configurations in an assembly of two pores and a throat. Pores and throats are shown with circles and rectangles for illustrative purposes only. They can have angular cross-sections and contain a center as well as a corner phase. Only the center phases are illustrated here. The corners will contain water if the elements are angular. The dotted curvatures show the Main Terminal Menisci (MTM's) present between the wetting and non-wetting phases.

Figure 3: Corner interface adjustments based on changes in local capillary pressure. (a) The contact angle is equal to the receding contact angle. The corner interface, i.e., AM moves towards the apex of the corner as the local capillary pressure increases. (b) The contact angle is greater than the receding contact angle. The corner interface hinges as the local capillary pressure decreases.

Figure 5: Local and inter-block elements. Pore i and throat ij are local to block A, which is assigned to processor a. Pore j is local to block B, which is assigned to processor b. Pore j and throat ij are inter-block elements to blocks A and B, respectively.

Figure 6: The algorithm flow chart of the dynamic pore network model presented in this work.

Figure 7: (a) The Berea sandstone core sample used in this work. (b) The pore network representation of the Berea sample used in this work. Pores and throats are depicted by red spheres and blue cylinders, respectively.

Figure 8: Three-phase segmentation of high resolution micro-CT images of Berea sandstone scanned at $2.49 \mu\text{m}$. (a) The gray-scale reference image obtained by scanning the dry core sample before the start of the experiments. (b) The pore-grain separated binary image obtained after performing histogram thresholding on the gray-scale reference image. Blue color represents the pore voxels. (c) The gray-scale image obtained by scanning the core during the experiment. The pore space contains two fluid phases, namely, oil and brine that is doped with 7.5 wt % NaI. (d) The labeled image obtained after the segmentation of image (c). Blue, red, and gray colors represent brine, oil and grain voxels, respectively.

Figure 9: In-situ measurements of brine-oil contact angle in pore corners in the Berea sandstone core sample. Blue, red, and gray colors represent the brine, oil, and grain voxels, respectively. The green lines are tangents drawn to the brine-oil interface and solid surface at triple contact points. The angles created by the green lines measured through brine are brine-oil contact angles at those locations.

Figure 10: Experiment 1 and Simulation 1 brine saturation profiles at the end of selected fractional flows. Dra, Imb, and ff stand for drainage, imbibition, and fractional flow, respectively. The measured data from Experiment 1 are shown with empty circles, while the predicted data from Simulation 1 are shown with solid lines. The first one-third of the micro-CT slices obtained during Experiment 1 in fractional flow number 3 were corrupted due to technical problems during image acquisition.

Figure 11: Fractional flow curves obtained from Experiment 1 and Simulation 1. The measured data from Experiment 1 during drainage and imbibition are shown with circles and squares, respectively. The predicted data from Simulation 1 are shown with triangles connected by solid lines.

Figure 12: Bentheimer sandstone two-phase relative permeabilities versus brine saturation. Predicted data from Simulation 1 shown by solid line are compared against experimentally measured data from the literature (Øren et al., 1998; Alizadeh and Piri, 2014) shown by circles and squares. (a) Drainage. (b) Imbibition.

Figure 13: Experiment 2 and Simulation 2 brine saturation profiles in the bottom, middle, and top of the medium at the end of first drainage and last imbibition fractional flows.

Figure 14: Experiment 2 and Simulation 2 brine saturation profiles in full length of the medium. (a) Drainage. (b) Imbibition

Figure 15: Fractional flow curves obtained from Experiment 2 and Simulation 2. The measured data from Experiment 2 during drainage and imbibition are shown with circles and squares, respectively. The predicted data from Simulation 2 are shown with triangles connected by solid lines.

Figure 16: Berea sandstone relative permeabilities versus brine saturation. The predicted data from Simulation 2 are compared against the measured data from Experiment 2 and the experimental data by Oak (1990). (a) Drainage. (b) Imbibition.

Figure 17: Experiment 3 and Simulation 3 brine saturation profiles in full length of the medium in imbibition fractional flows.

Figure 18: The effect of IFT on relative permeabilities of Bentheimer sandstone shown by comparing the results from Simulations 1 and 4. (a) Drainage. (b) Imbibition. IFT values in Simulations 1 and 4 were 46.34 mN/m and 1.0 mN/m, respectively.

Figure 19: The effect of viscosity ratio on relative permeabilities of Bentheimer sandstone shown by comparing the results from Simulations 1 and 5. (a) Drainage. (b) Imbibition. Wetting-phase-to-oil viscosity ratio in Simulations 1 and 5 were 1.31 and 5.0, respectively.

Figure 20: The combined effect of IFT and viscosity ratio on relative permeabilities of Bentheimer sandstone shown by comparing the results from Simulations 1, 4, and 6. (a) Drainage. (b) Imbibition. IFT values and wetting-phase-to-oil viscosity ratios in Simulations 1, 4, and 6 were 46.34 mN/m and 1.31, 1.0 mN/m and 1.31, and 1.0 mN/m and 5.0, respectively.

Figure 21: Wetting-phase fractional flow versus saturation obtained from Simulations 1, 4, 5, and 6. (a) Drainage. (b) Imbibition. IFT values and wetting-phase-to-oil viscosity ratios in Simulations 1, 4, 5, and 6 were 46.34 mN/m and 1.31, 1.0 mN/m and 1.31, 46.34 mN/m and 5.0, and 1.0 mN/m and 5.0, respectively.

Table 1: Previously-developed dynamic pore network models

Study	Largest network size ^a	Phenomena studied	Validation techniques
Koplik and Lasseter (1985)	100	Effect of N_c on trapping	N/A
Lenormand et al. (1988)	10,000	Flow regimes	Micro-models
Blunt and King (1991)	80,000	Drainage K_r	Buckley-Leverett
Lee et al. (1995)	524,288	Imbibition K_r , S_{or} , P_c	N/A
Kamath et al. (1996)	262,144	Saturation profiles, recoveries	Unsuccessful core-flooding
Xu et al. (1999)	131,072	Saturation profiles, recoveries	Recoveries in miscible flooding
van der Marck et al. (1997)	2,401	Pressure field in drainage	Micro-models viscosity ratio of one
Mogensen and Stenby (1998)	3,375	Trapping, S_{or}	N/A
Aker et al. (1998)	4,800	Pressure field in drainage	Glass beads viscosity ratio of one
Dahle and Celia (1999)	8,381	P_c in drainage	N/A
Hughes and Blunt (2000)	16,384	K_r , flow patterns	Micro-models

^aMaximum number of pores

Table 2: Previously-developed dynamic pore network models (cont'd)

Study	Largest network size ^a	Phenomena studied	Validation techniques
Constantinides and Payatakes (2000)	6,000	Wetting layers, S_{or}	N/A
Thompson (2002)	1,728	Imbibition flow patterns	N/A
Singh and Mohanty (2003)	1,920	Saturation profiles, K_r in drainage	Qualitative du Prey (1973)
Nordhaug et al. (2003)	5,000	Interfacial velocities	Sand pack Schaefer et al. (2000)
Løvoll et al. (2005)	12,800	Effects of viscosity, gravity in drainage	Glass beads tests
Al-Gharbi and Blunt (2005)	900	Displacement patterns in drainage	N/A
Nguyen et al. (2006)	12,349	Imbibition K_r , S_{or}	Oak (1990) Chatzis and Morrow (1984)
DiCarlo (2006)	12,349	Saturation overshoot	DiCarlo (2004)
Piri and Karpyn (2007)	20,890	Two-phase flow in fracture	Fluid occupancy Karpyn and Piri (2007)
Joekar-Niasar et al. (2010)	42,875	Non-equilibrium capillarity theory	Theoretical Hassanizadeh and Gray (1990)
Tørå et al. (2012)	767	Saturation profiles, resistivity index	Sandpack tests
Sheng and Thompson (2013)	1,532	Coupling with reservoir simulator	N/A

^aMaximum number of pores

Table 3: Properties of the Pore Network Representative of the Bentheimer Sandstone Core Sample Used in Experiment 1

Item	Throats	Pores	Total
Number	306,825	131,346	438,171
Porosity excl. clay (%)	9.697	13.631	23.328
Porosity incl. clay (%)	11.261	13.772	25.033
Absolute Permeability (mD)			2716
Length (mm)			12.977
Diameter (mm)			4.972
Minimum coordination number		0	
Maximum coordination number		150	
Average coordination number		4.622	
Minimum radius (μm)	0.28	0.30	0.28
Maximum radius (μm)	101.00	148.48	148.48
Average radius (μm)	13.71	25.96	17.38
Average shape factor	0.042	0.046	0.044
Triangular cross sections (%)	79.790	70.665	77.055
Square cross sections (%)	19.590	28.959	22.399
Circular cross sections (%)	0.620	0.376	0.546
Connected to the inlet	3363	0	3363
Connected to the outlet	3248	0	3248
Isolated clusters			45
Isolated	143	446	589

Table 4: Properties of the Pore Network Representative of the Berea Sandstone Core Sample Used in Experiments 2 and 3

Item	Throats	Pores	Total
Number	3,913,222	1,891,260	5,804,482
Porosity excl. clay (%)	8.236	12.616	20.852
Porosity incl. clay (%)	8.458	12.892	21.350
Absolute Permeability (mD)			638
Length (mm)			76.4
Diameter (mm)			4.58
Minimum coordination number		0	
Maximum coordination number		45	
Average coordination number		4.017	
Minimum radius (μm)	0.21	0.25	0.21
Maximum radius (μm)	63.50	101.0	101.0
Average radius (μm)	6.95	13.95	9.27
Average shape factor	0.039	0.047	0.042
Triangular cross sections (%)	78.522	57.667	71.592
Square cross sections (%)	20.954	41.594	27.813
Circular cross sections (%)	0.524	0.739	0.595
Connected to the inlet	1515	0	1515
Connected to the outlet	1507	0	1507
Isolated clusters			24
Isolated	7460	7791	15251

Table 5: Number of Experiments and Their Conditions and Procedures

Experiment no.	Core sample	Temp.(°C)/ Press.(MPa)	Confining press.(MPa)	Wetting phase	Non-wetting phase	Experimental procedure
1	Bentheimer sandstone	24/2.76	4.83	Brine 1.5 wt. % NaI	n-Decane	Steady state
2	Berea sandstone	24/0.90	1.52	Brine 7.5 wt. % NaI	Soltrol 170	Steady state
3	Berea sandstone	24/0.90	1.52	Brine 7.5wt. % NaI	Soltrol 170	Unsteady state

Table 6: Dimensions and Petrophysical Properties of the Core Samples Used in the Experiments

Experiment no.	Core sample	Diameter mm	Length mm	ϕ^a %	K_{abs} mD	Pore volume mm ³
1	Bentheimer sandstone	4.97	12.98	23.42	2568 ^b	58.97
2,3	Berea sandstone	4.58	76.40	21.69	623 ^c	273.01

^aHelium porosity

^bKlinkenberg-corrected helium permeability

^cBrine permeability

Table 7: Properties of the Fluids Used in the Experiments Measured at Experiment Conditions

Experiment no.	Fluid	Viscosity cP	Density gr/cm ³	IFT ^a mN/m
1	n-Decane	0.942	0.727	46.34
	Brine	1.237	1.009	
	1.5 wt % NaI			
2,3	Soltrol	2.851	0.774	41.33
	170			
	Brine	1.240	1.055	
	7.5 wt % NaI			

^aBrine-Oil interfacial tension

Table 8: Brine and Oil Flow Rates, Capillary Numbers, and Scanned Spots in Experiment

1

	FF no. ^a	$f_{\text{brine}}^{\text{b}}$	Q_{brine} cm^3/min	Q_{oil} cm^3/min	N_c	Scanned spots
Drainage	1	0.990	0.1	0.001	7.45×10^{-8}	Full
	2	0.909	0.05	0.005	3.72×10^{-7}	-
	3	0.667	0.02	0.01	7.45×10^{-7}	Full
	4	0.333	0.01	0.02	1.49×10^{-6}	-
	5	0.111	0.005	0.04	2.98×10^{-6}	-
	6	0.024	0.002	0.08	5.96×10^{-6}	Full
	7	0.010	0.001	0.1	7.45×10^{-6}	-
	8	0.005	0.001	0.2	1.49×10^{-5}	-
	9	0.003	0.001	0.4	2.98×10^{-5}	Full
Imbibition	1	0.010	0.002	0.2	1.96×10^{-7}	-
	2	0.039	0.004	0.1	3.91×10^{-7}	-
	3	0.138	0.008	0.05	7.83×10^{-7}	Full
	4	0.333	0.01	0.02	9.78×10^{-7}	-
	5	0.667	0.02	0.01	1.96×10^{-6}	Full
	6	0.889	0.04	0.005	3.91×10^{-6}	-
	7	0.976	0.08	0.002	7.83×10^{-6}	Full
	8	0.990	0.1	0.001	9.78×10^{-6}	-
	9	1	0.2	0	1.96×10^{-5}	Full

^aFractional flow number

^bFractional flow of brine

Table 9: Brine and Oil Flow Rates, Capillary Numbers, and Scanned Spots in Experiment

2

	FF no. ^a	f _{brine} ^b	Q _{brine} cm ³ /min	Q _{oil} cm ³ /min	N _c	Scanned spots
Drainage	1	0.952	0.1	0.005	5.07×10^{-7}	1,2,3
	2	0.833	0.05	0.01	1.01×10^{-6}	2
	3	0.5	0.02	0.02	2.03×10^{-6}	2
	4	0.167	0.01	0.05	5.07×10^{-6}	2
	5	0.048	0.005	0.1	1.01×10^{-5}	2
	6	0.007	0.001	0.15	1.52×10^{-5}	1,2,3
Imbibition	1	0.038	0.002	0.05	2.40×10^{-7}	2
	2	0.167	0.004	0.02	4.80×10^{-7}	2
	3	0.444	0.008	0.01	9.60×10^{-7}	1,2,3
	4	0.667	0.01	0.005	1.20×10^{-6}	2
	5	0.909	0.02	0.002	2.40×10^{-6}	2
	6	1	0.05	0	6.00×10^{-6}	1,2,3

^aFractional flow number^bFractional flow of brine

Table 10: Brine and Oil Flow Rates, Capillary Numbers, and Scanned Spots in Experiment

3

	FF no. ^a	Q _{brine} cm ³ /min	Q _{oil} cm ³ /min	N _c	Scanned spots
Drainage	1	0.001	0.15	1.52×10^{-5}	1,2,3
Imbibition	1	0.1	0	1.20×10^{-5}	1,2,3
	2	0.15	0	1.80×10^{-5}	1,2,3

^aFractional flow number

Table 11: Scanned Spots Locations Along the Berea Core Sample in Experiments 2 and 3

Spot no.	Middle of spot from inlet mm	Spot length mm
1	11.07	4.41
2	35.90	4.41
3	67.55	4.41

Table 12: In-Situ Brine-Oil Contact Angles Measured in the Bentheimer and Berea Sandstone Samples During Experiments and Used in Simulations

Core sample	Exp/ Sim no.	Process/ Type	Average θ_{AM}	Min θ_{AM}	Max θ_{AM}
Bentheimer sandstone	Exp 1	Drainage	22.83	10.81	32.33
		Imbibition	28.22	19.83	42.11
	Sim 1	Receding	22	12	32
		Advancing	45	35	55
Berea sandstone	Exp 2,3	Drainage	15.51	6.37	26.57
		Imbibition	35.59	7.83	56.14
	Sim 2,3	Receding	16	6	26
		Advancing	50	40	60

Table 13: Properties of the Fluids and Ranges of the Capillary Number in Simulations 4, 5, and 6

Simulation no.	Fluid	Viscosity cP	Density gr/cm ³	IFT mN/m	Drainage N _c range	Imbibition N _c range
4	NWP ^a	0.942	0.727	1.0	3×10^{-6} - 1×10^{-3}	9×10^{-6} - 9×10^{-4}
	WP ^b	1.237	1.009			
5	NWP	1.0	0.727	46.34	8×10^{-8} - 3×10^{-5}	8×10^{-7} - 8×10^{-5}
	WP	5.0	1.009			
6	NWP	1.0	0.727	1.0	4×10^{-6} - 1×10^{-3}	4×10^{-5} - 4×10^{-3}
	WP	5.0	1.009			

^aNon-wetting phase

^bWetting phase

- Dynamic pore network modeling of two-phase flow at the core-scale is presented.
- The model is used as a pore-to-core up-scaling platform.
- Miniature core-flooding experiments are performed and used to rigorously validate the model.