

How does the connectivity of open-framework conglomerates within multi-scale hierarchical fluvial architecture affect oil-sweep efficiency in waterflooding?

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ABSTRACT

Understanding multi-phase fluid flow and transport processes within aquifers, candidate reservoirs for CO₂ sequestration, and petroleum reservoirs requires understanding a diverse set of geologic properties of the aquifer or reservoir, over a wide range of spatial and temporal scales. We focus on multi-phase flow dynamics with wetting (e.g., water) and non-wetting (e.g., gas or oil) fluids, with one invading another. This problem is of general interest in a number of fields and is illustrated here by considering the sweep efficiency of oil during a waterflood. Using a relatively fine-resolution grid throughout a relatively large domain in these simulations and probing the results with advanced scientific visualization tools (Reservoir Visualization Analysis [RVA]/ParaView software) promote a better understanding of how smaller-scale features affect the aggregate behavior at larger scales. We studied the effects on oil-sweep efficiency of the proportion, hierarchical organization, and connectivity of high-permeability open-framework conglomerate (OFC) cross-sets within the multi-scale stratal architecture found in fluvial deposits. We analyzed oil production rate, water breakthrough time, and spatial and temporal distribution of residual oil saturation. As expected, the effective permeability of the reservoir exhibits large-scale anisotropy created by the organization of OFC cross-sets within unit bars, and the organization of unit bars within compound-bars. As a result, oil-sweep efficiency critically depends on the direction of the pressure gradient. However, contrary to expectations, the total amount of trapped oil due to the effect of capillary trapping does not depend on the magnitude of the pressure gradient within the examined range. Hence the pressure difference between production and injection wells does not affect sweep efficiency; although the spatial distribution of oil remaining in the reservoir depends on this value. Whether or not clusters of connected OFC span the domain affects only the absolute rate of oil production—not sweep efficiency.

INTRODUCTION

Multi-phase fluid flow and transport processes within aquifers, candidate reservoirs for CO₂ sequestration, and petroleum reservoirs are affected by geologic heterogeneity in ways that are not fully understood. In addition to advancing basic science, this area of research can contribute to solving societal problems such as remediating contaminated aquifers, reducing greenhouse gas emissions, and improving oil recovery. The uncertainty about site-specific geology stems from the inherent variation in reservoir properties, which in sedimentary reservoirs is controlled by the depositional environments in which they were formed. Understanding subsurface flow dynamics requires understanding a diverse set of geologic properties of the aquifer or reservoir over a wide range of spatial and temporal scales. Historically, aquifer and reservoir modeling has tended to aggregate parameters across scales because the direct representation of smaller-scale features has not been computationally tractable. Advances in high-performance computing have now made it possible to represent reservoir properties over a broad range of spatial scales within one model. When small-scale features are represented, smaller-scale processes can be studied directly and differentiated from their cumulative effect on reservoir-scale processes (e.g., Scheibe et al., 2015). In this context, recent studies have focused on the connectivity of sedimentary units having higher intrinsic permeability, which can form preferential flow pathways (e.g., Guin et al., 2010). New research has produced quantitative models for the spatial distribution of sedimentary units across a wide range of scales, especially for deposits created by fluvial processes (e.g., Lunt et al., 2013). This success has, in turn, led to new methods for creating digital geologic models representing this range of scales (e.g., Ramanathan et al., 2010).

This article involves a nexus of these areas of research. We focus on multi-phase flow dynamics with wetting (e.g., water) and non-wetting (e.g., gas or oil) fluids, with one invading another. This problem is of general interest in a number of fields and is illustrated here in considering how the sweep efficiency of oil during a waterflood is affected by heterogeneity at multiple scales within geologic models. Recent work on this problem has included new

ideas on the sedimentology in fluvial channel-belt deposits across a range of spatial scales, new ways of creating digital geologic models that represent this multi-scaled sedimentary heterogeneity, new ideas for quantifying the connectivity of preferential flow pathways across this range of scales, and new efforts in using high-performance computing to simulate multi-phase fluid flow dynamics (e.g., Gershenzon et al., 2015). Using a relatively fine resolution grid throughout a relatively large domain in these simulations promotes a better understanding of how smaller-scale features affect the aggregate behavior at larger scales. The results thus far have generated interesting insights, especially how these features affect the capillary trapping of oil and, thus, the sweep efficiency of waterflooding. In some cases these results are counterintuitive. In this article, we continue to explore this problem by probing the results with advanced scientific visualization tools. These explorations confirm and more fully support previous results and better clarify the underlying processes.

■ BACKGROUND

Oil-sweep efficiency during waterflooding is fundamentally controlled by the nature of immiscible displacement of a non-wetting liquid by a wetting liquid in porous media (Buckley and Leverett, 1942). This process includes the effects of capillary pressure and relative permeability on oil trapping and early water breakthrough (Kortekaas, 1985; Corbett et al., 1992; Khataniar and Peters, 1992; Wu et al., 1993; Gharbi et al., 1997; Kaasschieter, 1999). Such immiscible displacement is, in turn, controlled by the three-dimensional heterogeneity and anisotropy in permeability (Kjensvik et al., 1994; Jones et al., 1995; Tye et al., 2003; Choi et al., 2011). In sedimentary reservoirs, the three-dimensional heterogeneity and anisotropy is controlled by the architecture of the sedimentary deposits.

Recent studies have led to new conceptual and quantitative models for sedimentary architecture in fluvial deposits over a range of scales that are relevant to the performance of some important petroleum reservoirs (Tye et al., 2003; Lunt et al., 2004a, 2004b; Bridge, 2006; Lunt and Bridge 2007). As shown in Figure 1, braided channel-belt deposits are characterized by a large-volume fraction of convex-up, bar deposits formed within channels. Only when channels are abandoned and filled are “channel-shaped” units formed. Created during lower-energy flow conditions, these concave-up channel fills are low-permeability baffles within the channel belts. In gravelly channel-belt deposits, preferential flow pathways arise from the interconnection of open-framework gravels within lobate unit bar deposits (Lunt and Bridge, 2007). These are the “thief zones” within reservoirs that have a negative effect on oil recovery (McGuire et al., 1994, 1999a, 1999b; Tye et al., 2003).

Lunt et al. (2004a, 2004b) studied the gravelly channel belt of the Sagavanirktok River, Alaska (Fig. 1), a modern analog for deposition of the Ivishak Formation in Prudhoe Bay field, Alaska, and quantified the proportions and lengths for sedimentary unit types, or facies, across relevant scales (Table 1).

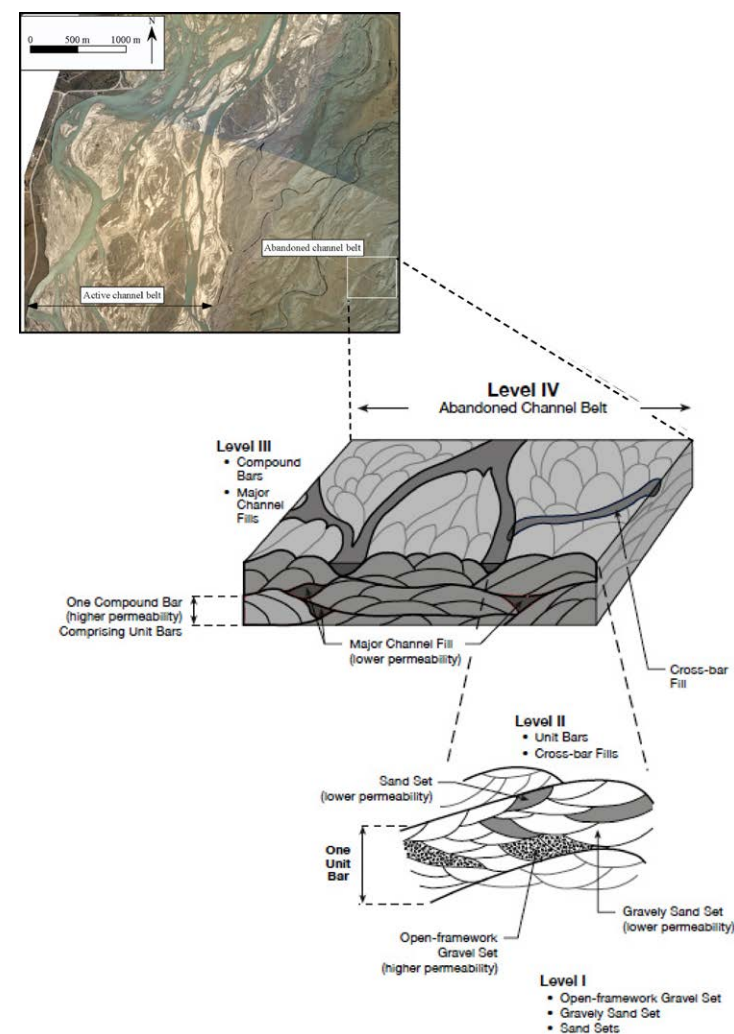


Figure 1. (Top) Aerial photograph of the portion of the Sagavanirktok River studied by Lunt et al. (2004a) with the active channel belt and the preserved channel belt deposits identified. (Middle and Bottom) Conceptual model for the hierarchical sedimentary architecture found in channel-belt deposits (Lunt et al., 2004a) (see also Table 1). The compound-bar deposits (level III) result from the processes of unit-bar accretion and channel migration. Within unit-bar deposits (level II), sets of open-framework gravel (level I) have the highest permeability. As channels are abandoned, they are filled with lower-permeability sediment. Major channel fills (level III) and smaller cross-bar channel fills (level II) are lower-permeability baffles within the deposit. From Ramanathan et al. (2010).

TABLE 1. HIERARCHY OF UNIT TYPES FROM LARGEST (IV) TO SMALLEST (I) STRATA TYPES

IV	Channel-belt deposit				
III	Compound-bar deposits ¹				Major channel fills
II	Unit-bar deposits			Cross-bar channel fills	Concave-up sand
I	Open-framework gravel set ²	Gravelly sand set	Sand set	Concave-up sand	Concave-up sand

¹Typical dimensions (largest unit type): 750 × 500 × 2 m³.

²Typical dimensions (smallest type): decimeters to meters long and wide, centimeters to decimeters thick (Lunt et al., 2004a, 2004b).

At the smallest scale, sets of cross-stratified (“cross-sets” herein) sand, sandy gravel, and open-framework gravel (decimeters thick and meters long) occur within unit bar deposits (tens of decimeters thick and tens of meters long). Unit bars and cross-bar channel fills occur within compound-bar deposits (meters thick and hundreds of meters long). Compound-bar deposits and the channel fills that bound them occur within channel belts (tens of meters thick and kilometers long). Importantly, the open-framework gravel cross-sets were found to make up 25%–30% of the volume of the deposit. These sedimentary unit types are preserved with similar lengths and proportions within the Victor interval of the Ivishak Formation (Tye et al., 2003). The Victor interval has few shales or other vertical permeability barriers, and connected cross-sets of open-framework conglomerates (i.e., lithified open-framework gravels, referred to as OFC hereafter) are the dominant control on reservoir performance (McGuire et al., 1994, 1999a, 1999b; Tye et al., 2003).

The sedimentary architecture quantified by Lunt et al. (2004a, 2004b) was incorporated by Ramanathan et al. (2010) into a high-resolution, three-dimensional, digital model using geometric-based simulation methods. This model was used to investigate how the spatial variations in reservoir properties (relative permeability and capillary pressure) affect oil-sweep efficiency in waterflooding (Gershenson et al., 2015).

Some of the results revealed nuances that complement conventional understanding. For example, it is known that anisotropy affects sweep efficiency and that a pair of injector and producer wells should be aligned perpendicular to the principal direction of anisotropy to maximize efficiency (Rose et al., 1989). The hierarchical stratal architecture in Figure 1 includes preferential-flow pathways through higher-permeability OFC units, which differ with scale and direction. The net influence creates anisotropy in the bulk effective permeability, and indeed sweep efficiency in these simulations was found to be greater when the injector/producer pair is aligned normal the paleoflow direction (i.e., the orientation of the channel belt) as compared to alignment parallel to paleoflow direction (Gershenson et al., 2015), as expected. However, some of the related results are counter to conventional understanding and need to be further explored.

One such result relates to how efficiency varies with pressure gradient. During immiscible oil displacement, oil is trapped due to reservoir heterogeneities in both permeability and capillary pressure (Kortekaas, 1985; Wu

et al., 1993; Kaasschieter, 1999). It has been previously shown that the trapping effect, and hence oil-sweep efficiency, depends on the pressure gradient (Corbett et al., 1992). In the high-resolution simulations of a fluvial reservoir, Gershenson et al. (2015) found that the value of the pressure gradient affects the spatial distribution of oil remaining in the reservoir, but does not affect the overall oil-sweep efficiency. These results indicate that the amount of oil trapped in isolated OFC strata sets is offset by the amount of oil moving out of surrounding sandstone and through connected OFC cross-sets.

Another surprising result relates to the effect of heterogeneity on fingering of the waterfront. Because the contrast in permeability between OFC and sandstone is large and because the size of OFC-connected pathways considerably exceeds the cell size in the model, it was expected that the waterfront would show large-scale fingering. However, fingering was not observed in any of the reservoir realizations (Gershenson et al., 2015). Even so, most of the oil (80%–95%) reached the production well through connected OFC pathways.

Finally, it was surprising that oil-sweep efficiency did not strongly depend on the proportion of open-framework conglomerate in the reservoir. The existence of OFC pathways depends upon proportion. When the proportion of OFC is above 20% of the deposit by volume, there are connected pathways through OFC that span the reservoir in any direction (“percolate” in the field of percolation theory), and when the proportion is below 20%, the pathways do not span (Guin and Ritzi, 2008; Guin et al., 2010). Simulations were performed in which the proportion of OFC was systematically varied across this threshold percentage, and the presence and/or absence of spanning pathways was confirmed. However, the presence and/or absence of connected pathways through OFC did not abruptly affect oil-sweep efficiency (Gershenson et al., 2015).

The above-mentioned specific behaviors of waterflooding processes are not intuitive and need to be further explored. The goal of this article is to further investigate these behaviors and to provide a more complete description of the observed processes. The Reservoir Visualization Analysis (RVA) software (Keefer et al., 2012) built on the ParaView open-source platform (<http://rva.cs.illinois.edu/index.html>) was used to further visualize, analyze, and illustrate our results. We first provide a description of the reservoir model and the methodology for reservoir simulation and analysis, followed by results, discussion, and conclusions.

METHODOLOGY

Geocellular Model for Reservoir Architecture

New approaches have been developed for creating digital models that reproduce the multi-scaled and hierarchical architecture in fluvial channel-belt deposits (e.g., Ramanathan et al., 2010; Hassanpour et al., 2013). This approach preserves architectural information within any gridding scheme used to create geocellular (i.e., discretized) models intended for flow and transport simulation. We adapted the method of Ramanathan et al. (2010) to create a geocellular model for the hierarchy of unit types in Table 1, for the purposes of computational experiments for studying the waterflood of an Ivishak-type reservoir, i.e., a reservoir exhibiting heterogeneity as described by Lunt et al. (2004a, 2004b) and as illustrated in Figure 1. In this method, a hierarchical geometric-based model of the multi-scaled facies architecture is first created, which is defined continuously over space. At each hierarchical level, stratal units are created using piecewise planar polyhedral elements. These are then combined into a global coordinate system with typically only pieces of them preserved, according to rules based on depositional processes. For example, Figures 2A and 2B show how unit-bar deposits are created as an assemblage within compound-bar deposits. In the same general way, cross-sets are created in assemblages populating unit bar deposits (Fig. 3). In a second step, the geometric model is sampled on a grid to create a geocellular model of the geologic architecture (Figs. 2C and 2D). The digital model can be created (and recreated) from the geometric model for all or part of the global domain, with any desired grid resolution that suits the flow modelers. Petrophysical properties are mapped into the geocellular model from statistical distributions defined per strata type I textural facies type and, thus, with a resolution smaller than the smallest facies.

Guin et al. (2010) confirmed that the approach creates a hierarchy of sedimentary unit types that honor the proportions, geometries, and spatial distribution of the unit types quantified in natural deposits at each level by Lunt et al. (2004a, 2004b). Figure 3 shows a cross section through an extracted piece of a simulated compound-bar deposit sampled with fine resolution (additional simulations showing larger-scale architecture are given in Ramanathan et al. [2010], fig. 10).

The cross-sets of high-permeability open-framework conglomerate (OFC) are simulated discretely. The OFC cells are considered to be connected in a cluster when cell faces are adjacent. Importantly, clusters of continuously connected OFC cells create preferential flow pathways. When OFC cross-sets comprise at least 20% of the volume of the deposit, clusters span opposing pairs of domain boundaries (Guin et al., 2010). Such spanning, preferential-flow pathways have been inferred to exist within the Ivishak Formation (Tye et al., 2003). The number, size, and orientation of OFC clusters in the geocellular model change with proportion. At any given proportion, the number, size, and orientation of clusters change across the different hierarchical levels (scales) of the stratal architecture. Connected OFC cells within individual cross-sets form

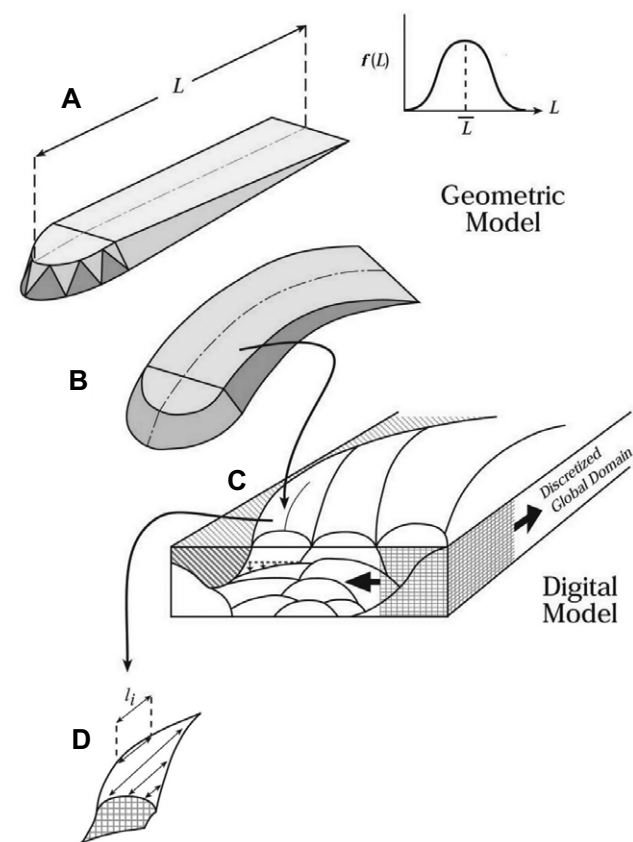


Figure 2. Steps in creating the geometric and geocellular models. (A) Creating an archetypal polyhedron with piecewise-planar elements. The archetypal polyhedron is formed from a parsimonious number of input geometric lengths drawn from statistical distributions. The polyhedron initially has a straight centerline. (B) Adding curvature to the centerline. (C) Merging with other unit types according to rules of deposition. In the same way, cross-set polyhedra are created and fill the unit bars, etc. (not shown). In a second step, a geocellular (digital) model (C) is created on a regular voxel grid of any desired resolution. (D) Only pieces of the archetypal unit bars are preserved in the geometric and geocellular models of the preserved deposit.

paths that vertically span single unit-bar deposits. Connections across unit-bar boundaries enhance lateral branching, and the many clusters within unit bars connect into a smaller number of larger clusters at the scale of multiple unit bars. At the scale of a whole compound-bar deposit, these clusters are typically connected into one or two large, spanning clusters. The spanning clusters occur at proportions of open-framework gravel cells below the theoretical

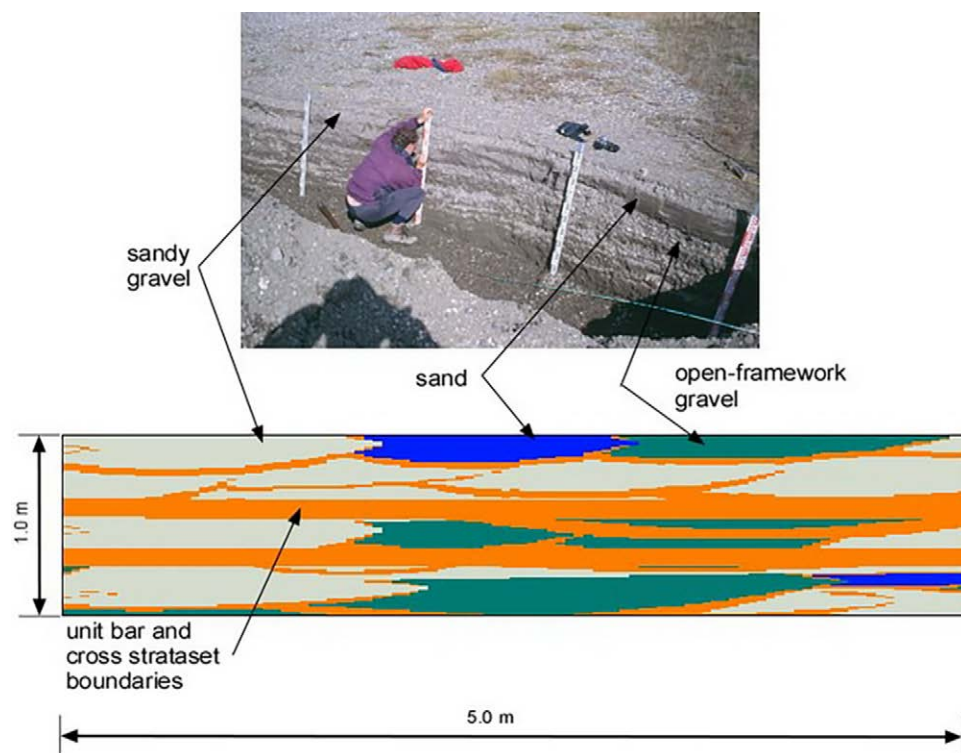


Figure 3. (Top) Exposure of channel-belt deposits in a trench at the Sagavanirktok River field site (from Lunt, 2002). (Bottom) Rendering of an extracted piece of a geometric model produced using the approach illustrated in Figure 2. View is oblique but nearly parallel to paleoflow direction. Boundaries of unit types have been given an orange color to distinguish individual unit-bar deposits and cross-set boundaries (thickness of the boundary is arbitrary). No vertical exaggeration.

threshold (31%) for random infinite media predicted in the mathematical theory of percolation. Guin and Ritzi (2008) showed that this is caused by geological structure within a finite domain. The percolation theory shows why two-dimensional models under-represent true three-dimensional connectivity, and thus why simulations must be three-dimensional (3D) (Huang et al., 2012).

Multi-Phase Flow Simulations

We simulated 3D immiscible oil displacement by water (black oil approximation) with ECLIPSE (Schlumberger Reservoir simulation software, version 2010.2). The highly nonlinear nature of the flow equations creates a significant challenge to obtaining computationally convergent solutions, and currently limits us to simulations of a modest reservoir size. Our goal is to eventually grow the problem to larger domains with finer resolution. The top of the reservoir model is taken to be at a depth of 2560 m (8400 ft). The size of the reservoir in the x , y , and z directions is $L_x = 200$ m (656 ft), $L_y = 200$ m (656 ft), and $L_z = 5$ m (16.4 ft), respectively. This encompasses the heterogeneity created by

an assemblage of unit bars within a compound bar. The reservoir is divided into one million cells with cell size 2:2:0.05 m in the x , y , and z directions, respectively.

We generated six realizations of the reservoir volume, each with a different proportion of OFC (Table 2) using the method (Ramanathan et al., 2010) described above. As shown in Table 2, the proportion of OFC affects the proportion of high-permeability cells that are connected to create preferential flow pathways. We consider clusters to span opposing boundaries when their extent in x , y , and z directions is equal to the domain size in those directions. Thus, the reservoir models range from one with more than 90% of all OFC cells connected in one spanning cluster (realization 1) to those with no spanning cluster (realizations 5 and 6). Figure 4 shows realizations 1, 4, and 6 with 28%, 22%, and 16% of OFC cells, respectively. The blue color indicates the OFC cells. Although it is not obvious from Figure 4, realization 1 (C) incorporates almost all OFC cells (90%) in one spanning cluster; realization 4 (B) has one spanning cluster (55% of all OFC cells); and realization 6 (A) has no spanning clusters. The RVA/ParaView visualization package facilitated filtering out connected clusters and rendering images of them. Figure 5 displays the

TABLE 2. PARAMETERS OF SIX REALIZATIONS

Realization no.	OFC proportion (%)	Geometric mean permeability (mD)	Proportion of connected OFC cells among OFC cells (%)	Do clusters span opposing boundaries?	Mean size OFC and/or sandstone clusters (x direction)	Mean size OFC and/or sandstone clusters (y direction)	Mean size OFC and/or sandstone clusters (z direction)
1	28	226	91	Yes	1.6/4.0	2.8/6.7	3.1/7.5
2	26	205	85	Yes	1.5/4.3	2.8/7.3	3.0/8.0
3	24	193	71	Yes	1.5/4.4	2.5/7.4	2.8/8.2
4	22	174	53	Yes	1.4/4.8	2.6/8.5	2.8/9.1
5	19	149	6.8	No	1.3/5.6	2.2/8.9	2.6/10.5
6	16	136	0.9	No	1.3/6.1	2.3/10.7	2.4/11.3

Note: OFC—open-framework conglomerates. The six realizations are: proportion of OFC material (column 2); geometric mean permeability (column 3); proportion of connected OFC cells among OFC cells (column 4); presence and/or absence of spanning clusters in realization (column 5); and mean size of OFC and sand clusters in x, y, and z directions (last three columns).

same realizations, but only OFC cells are shown. Figure 5 illustrates that OFC cells are densely interconnected in all considered cases; although the distributions of OFC material between spanning and non-spanning clusters are very different among these realizations. As we will demonstrate later, the existence of this “small-scale dense net” explains the main features of waterflooding in fluvial reservoirs. Figure 6 shows the five largest clusters of realization 4; the largest cluster is a spanning cluster.

The saturated permeability in sandy-gravel deposits (and of their lithified equivalents—pebbly sandstones and sandy conglomerates) varies nonlinearly as a function of the volume of sand mixed with gravel (see fig. 6 in Ramanathan et al., 2010; see also Klingbeil et al., 1999; Conrad et al., 2008). Sandy-gravel strata have permeabilities similar to the sand they contain, which are of the order of 10^0 to 10^1 Darcies (D). Thus, sand and sandy-gravel cross-sets within unit bars have permeabilities similar to channel-fill sands. Open-framework gravels have permeabilities of the order of 10^3 to 10^4 Darcies. In either type of strata, the coefficient of variation in permeability is of the order of unity. In the lithified stratatypes within the Ivishak Formation (sandstones, pebbly sandstones, and open-framework conglomerates), the saturated permeabilities scale down accordingly, and following Tye et al. (2003), the geometric mean for saturated permeability of sandstones and pebbly sandstones is taken to be 66 milliDarcies (mD) in this study. Because these two lithotypes are assigned the same permeability distribution in the simulations, we refer to them collectively as “sandstone.” Furthermore, the geometric mean saturated permeability of OFC is taken to be 5250 mD. Within all these lithotypes, log-normal permeability distributions were used, as are found in natural deposits (e.g., Conrad et al., 2008). The permeability from each distribution is randomly mapped into each cross-set from the appropriate distribution (i.e., the model does not represent spatial correlation below the scale of a cross-set). Figure 7 shows the distributions of lithotypes and permeability for two realizations. Figure 8 shows the permeability distributions for realizations 1

and 6. The percentage of cells with permeability in each specified range is also shown. While the percentage of material with high permeability is different between these two cases, the common features are: (1) The majority of cells have permeability less than 1 D. (2) The second maximum in permeability distribution is in the range from 3 to 4 D. The latter range brackets the geometric average of permeability of all OFC cells. (3) The cells with permeability inside of each range connect to small-scale (compared with reservoir-size) networks in all ten considered ranges of permeability. We did not include cell-scale anisotropy in the simulations, i.e., the ratio between vertical and horizontal permeability is unity, so that the effective anisotropy imparted by the simulated fluvial architecture, alone, could be observed.

Initially the reservoir contains oil with dissolved gas and connate water in equilibrium. Two different property characteristic curves were utilized for the sandstone and OFC lithotypes. These curves define the relations between water-relative permeability, oil-in-water relative permeability, water-oil capillary pressure, gas-relative permeability, and water saturation. Figure 9 shows the relative permeability and capillary pressure as a function of water saturation for sandstone and OFC lithotypes (see also Gershenson et al., 2015, for more details).

Porosity of both lithotypes is 0.2. Irreducible water saturation is 0.256 for sandstone and 0.1 for OFC. Residual oil saturation is 0.3. At the reference pressure of 4014.7 psi (hydrostatic pressure at a depth of 2560 m), the water formation volume factor is 1.029 rb/stb = rm^3/sm^3 (rb/stb = reservoir condition barrel/stock tank barrel or barrel at surface conditions), the water viscosity is 0.31 cP (1 cP = 1 centipoise = 0.01 gram per centimeter-second; 1 cP = 0.01 g/cm/s), and the water and rock compressibility factors are 3.13×10^{-6} and 3.0×10^{-6} 1/psi, respectively. The oil, water, and gas gravities at surface conditions are 23.5, 1.04, and 0.8, respectively.

Two different placements had been used for injection and production wells: (1) parallel to the direction of paleoflow utilized in constructing the reservoir

Figure 4. Distribution of sandstone (red) and open-framework conglomerate (OFC) (blue) in (A) realizations 6 (16% of OFC); (B) 4 (22% of OFC); and (C) 1 (28% of OFC). Paleoflow is from right to left. The reservoir size is 200:200:5 m. Vertical exaggeration is 10x.

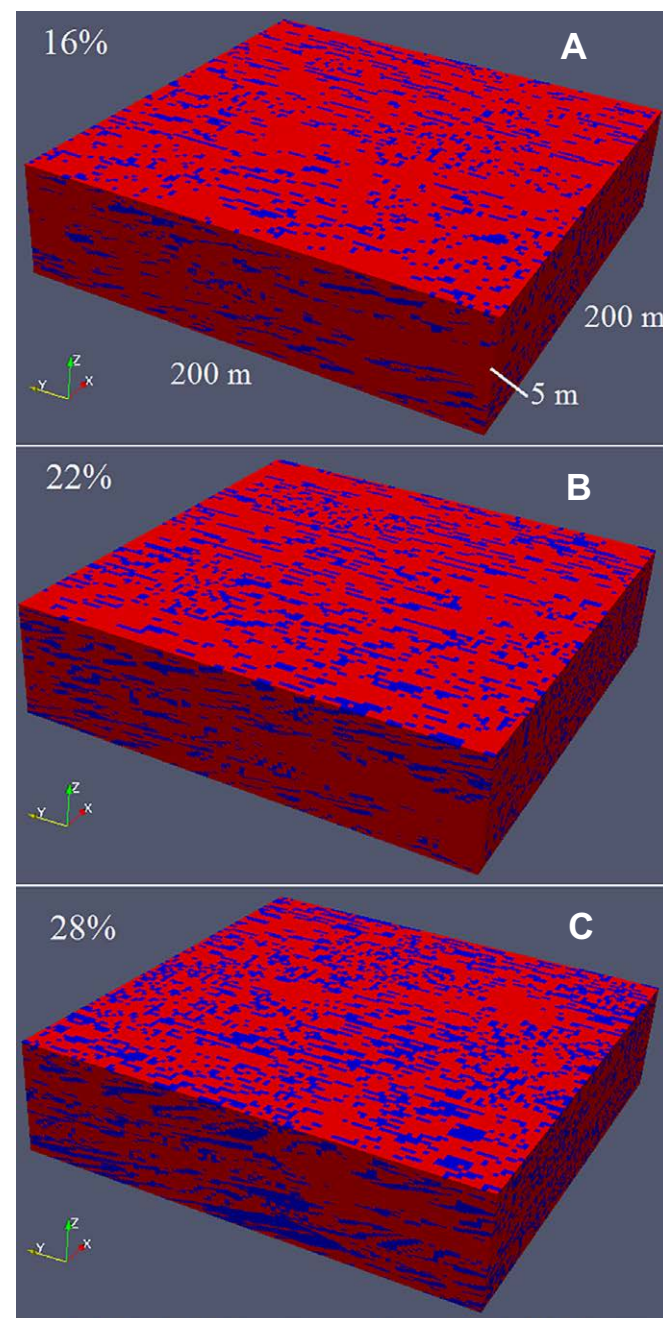
realizations, which is in the (y) direction (coordinates of the injection well are $x = 100$ m, $y = 20$ m; coordinates of the production well are $x = 100$ m, $y = 180$ m) (see Fig. 10); (2) perpendicular to paleoflow in the (x) direction (coordinates of injection well are $x = 20$ m, $y = 100$ m; coordinates of production well are $x = 180$ m, $y = 100$ m). In the simulations, the bottom-hole pressure has been specified for both wells. We utilized values for the pressure difference between injection and production wells from 100 to 800 psi.

RESULTS AND DISCUSSION

Under conditions described above, the water injection rate and the oil and water production rate ranges from 160 stb/day (stb = stock tank barrel or barrel at surface conditions) or 23% original oil in place (OOIP)/yr (reservoir realization 6, pressure difference 100 psi, wells placed perpendicular to paleoflow direction) to 3000 stb/day or 435% OOIP/yr (reservoir realization 1, pressure difference 800 psi, wells placed along paleoflow direction). Figure 11 illustrates the oil and water production rates as a function of time and shows that the production rates change in time while the pressure difference between wells is constant. Figure 12 shows oil and water production rates as a function of injected water volume for the six modeled realizations (Table 1) at a single pressure difference (i.e., 200 psi) between the injector and producer wells.

Study of Anisotropy

The fluvial architecture represented in our model creates anisotropy in which the bulk effective permeability in the paleoflow direction (y) differs from the effective permeability in the direction normal to the paleoflow (x) (Guin et al., 2010). Also, the effective permeability in the horizontal directions is very different from that in the vertical direction (z) (see Table 2). As stated above, we did not include cell-scale anisotropy in the simulations so that this effective anisotropy imparted by the simulated fluvial architecture, alone, could be observed. To consider how the anisotropy affects the process of oil displacement, we compared results of simulations with the pressure gradient along the y direction to the same case with the pressure gradient along the x direction. Gershenzon et al. (2015) showed that the results are essentially the same for gradients in the positive and the negative coordinate directions in each case. Therefore, the orientation of the OFC strata is not a factor, and we only show results for the positive directions. Figure 10 clearly illustrates the effects of anisotropy.



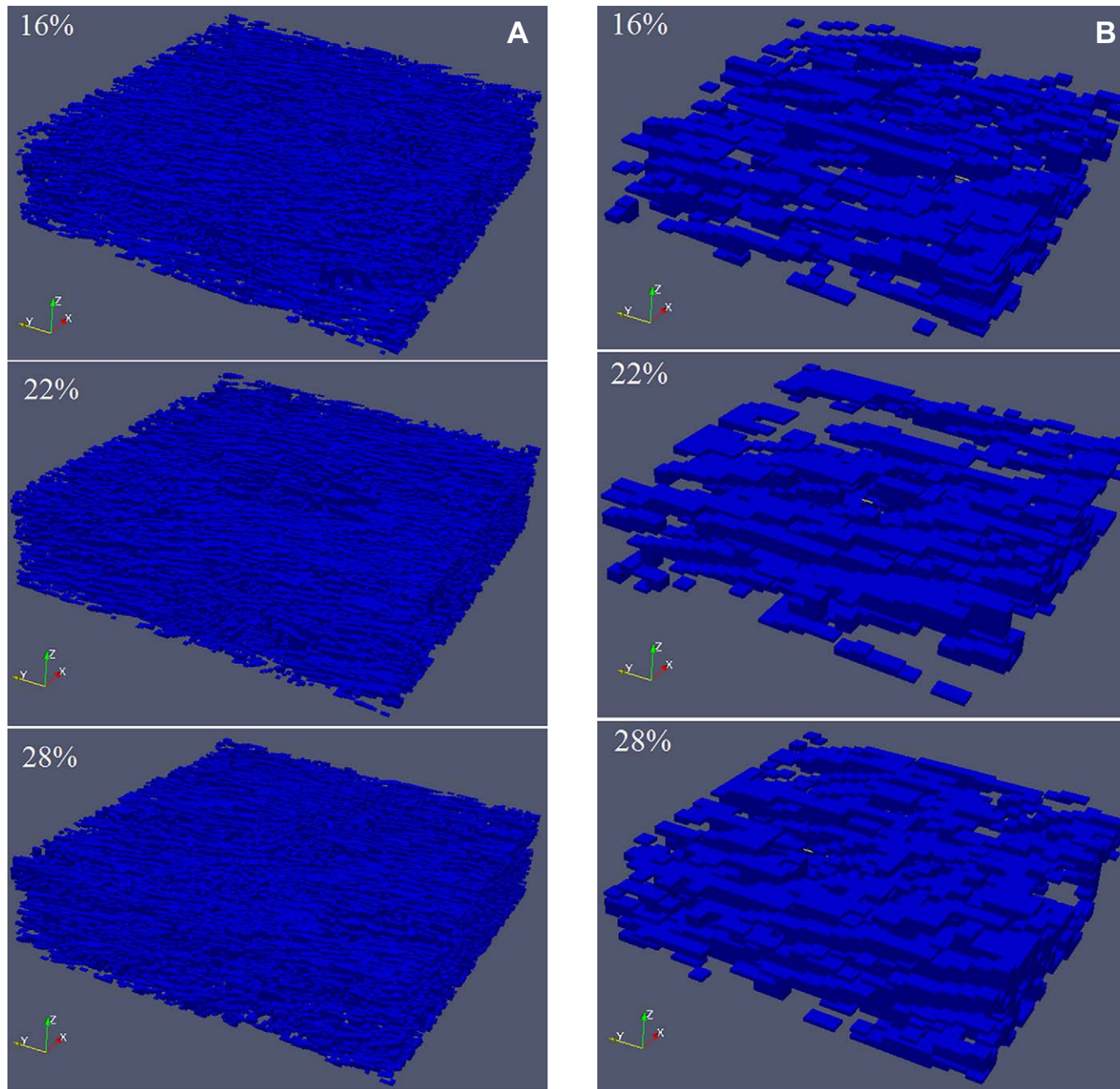


Figure 5. (A) Distribution of open-framework conglomerate (OFC) in realizations 6 (16% of OFC; top panel), 4 (22% of OFC; middle panel), and 1 (28% of OFC; bottom panel). The reservoir size is 200:200:5 m (100:100:100 cells). Vertical exaggeration is 10x. (B) The distribution of OFC in portions of the realizations shown in (A). The domain shown is 50:50:1.25 m (25:25:25 cells).

Figure 6. The five largest clusters of open-framework conglomerate (OFC) in realization 4 (proportion of OFC is 22%) are depicted after extracting them from the entire volume. The largest cluster spans the entire domain (i.e., is a spanning cluster) and is ~200:200:5 m (100:100:100 cells).

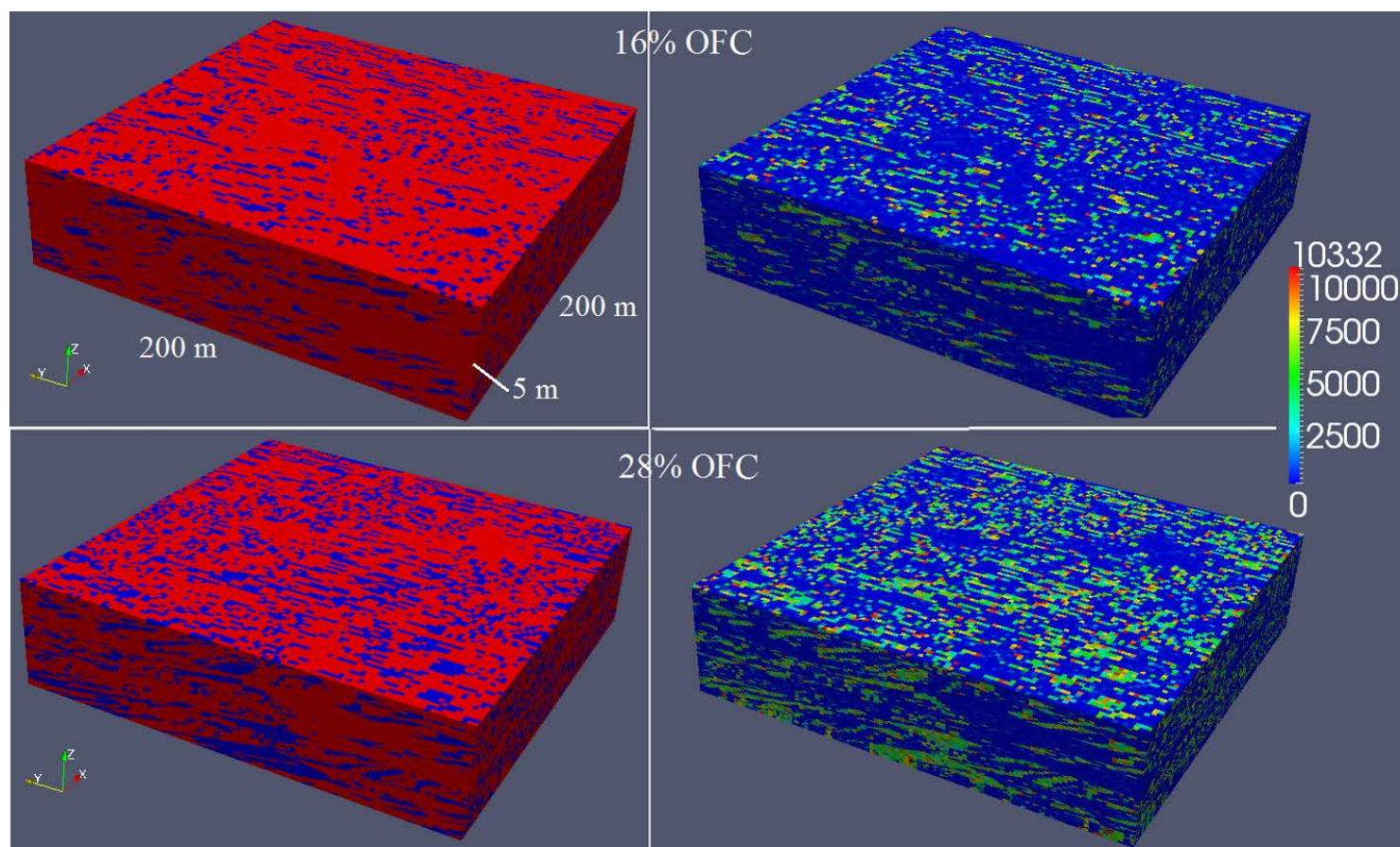
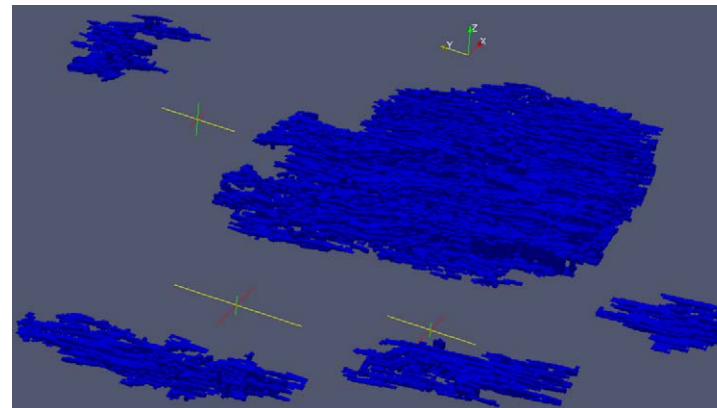


Figure 7. Image of reservoir with 16% (top) and 28% (bottom) of open-framework conglomerate (OFC). Panels on the left show distribution of sandstone (red) and OFC (blue), and panels on the right show the corresponding permeability.

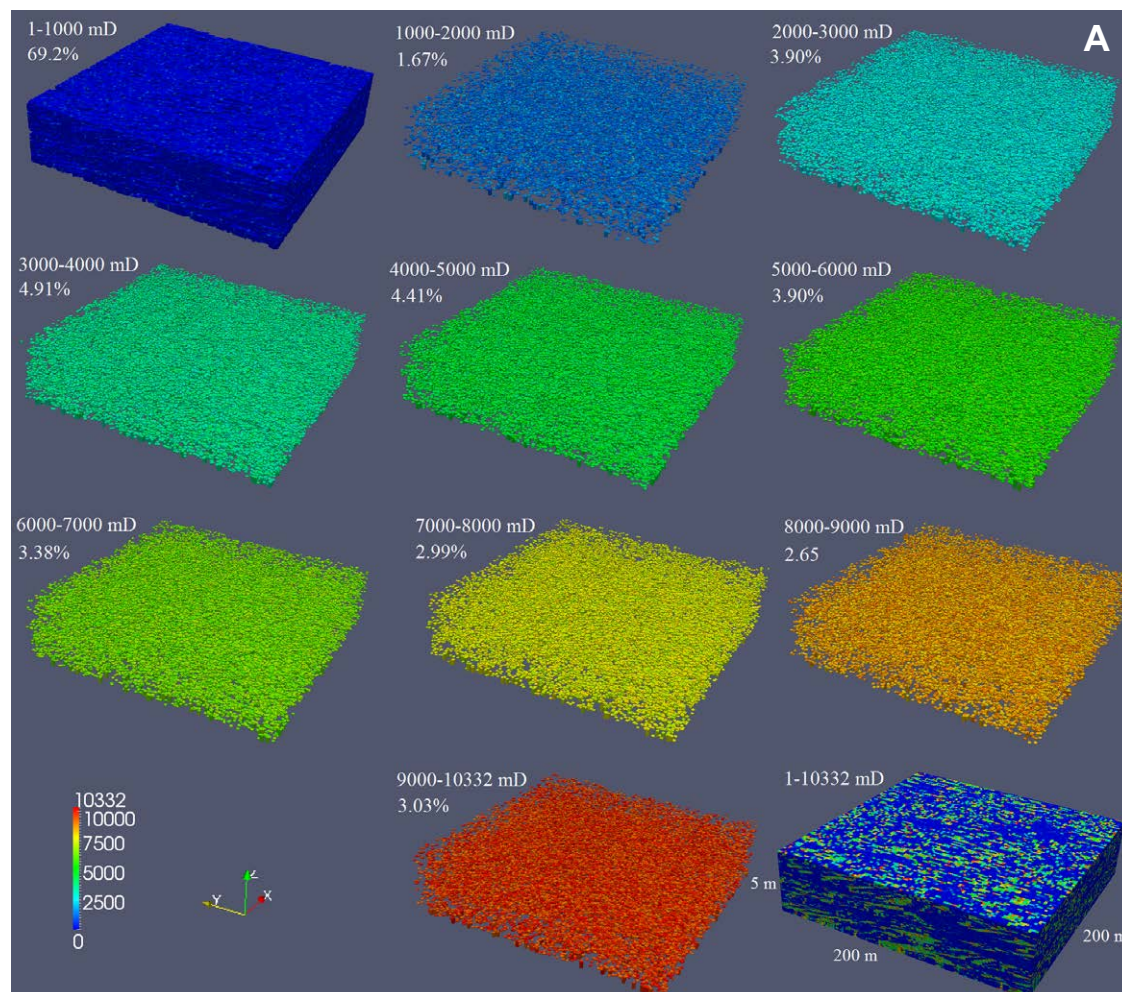


Figure 8 (on this and following page). (A) Images of permeability map for the realization of reservoir with 28% of open-framework conglomerate (OFC). Each image shows all cells with permeability in the range indicated at the top of the image. The percentage of cells with permeability in specified range from the total cell number is also shown.

Under the same pressure gradient between injection and production wells, the waterflood front propagates faster when the pressure gradient is in the y direction. The front is broader when the pressure gradient is in the x direction, so that a larger volume of the reservoir is swept (see animation in Fig. 13). This qualitative result illustrates why sweep efficiency increases if the injector and producer are aligned normal to the paleoflow direction (see Table 3) and supports the values for sweep efficiency reported in Gershenzon et al. (2015; see their figs. 7–10).

Anisotropy can also be understood in terms of the sizes of the sandstone and OFC clusters in x , y , and z directions (see Table 2). The mean

size of both sandstone and OFC clusters in the paleoflow direction is almost double the size of the clusters normal to paleoflow horizontal direction for all realizations. Figures 6 and 14 clearly illustrate that most of the clusters are elongated in the paleoflow direction. Anisotropy is caused by the way OFC cross-sets are organized within the stratal architecture at larger scales.

Anisotropy in the vertical direction is even more dramatic. The difference in cluster size between horizontal and vertical directions ranges from 20 (x direction) to 40 (y direction) times (see Table 2).

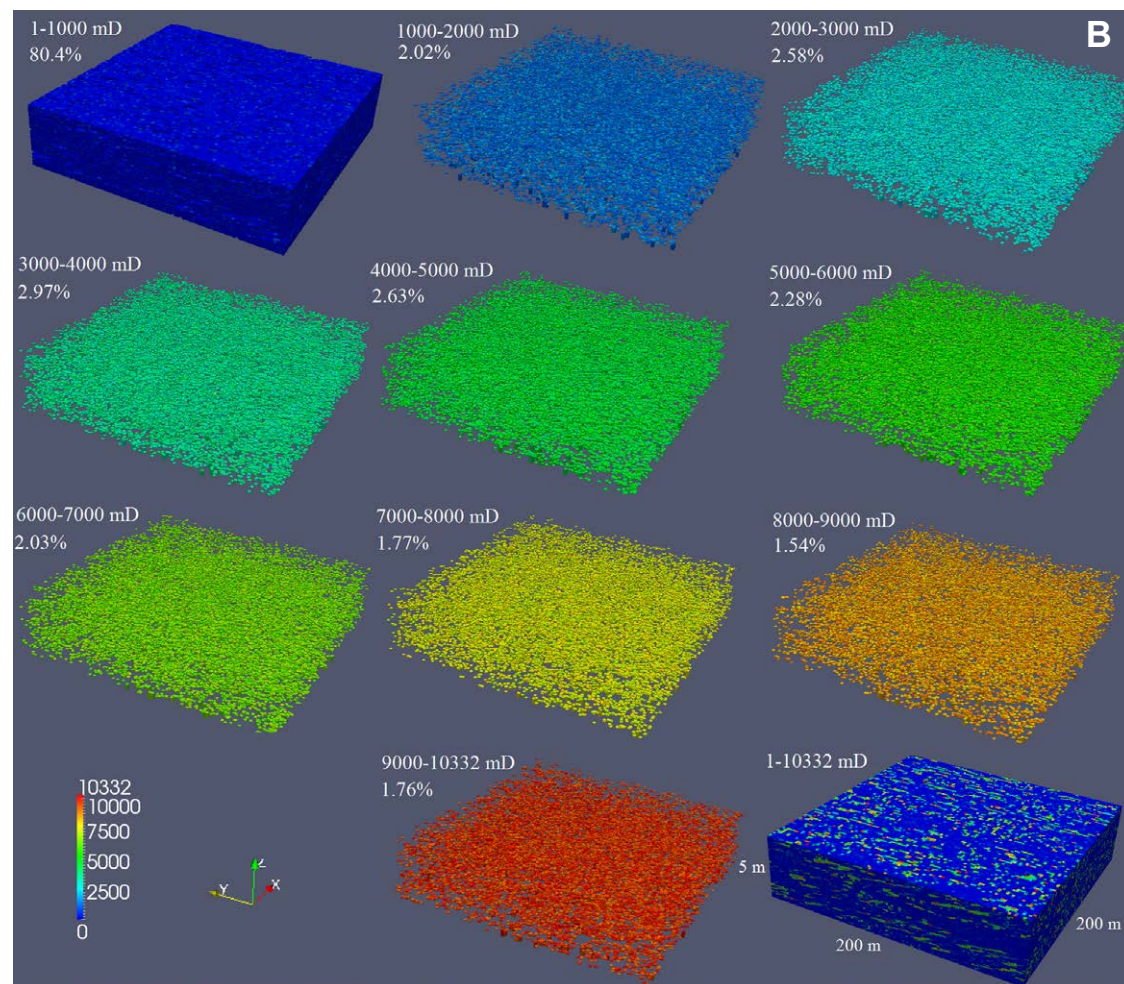


Figure 8 (continued). (B) The same as (A) for the realization of reservoir with 16% of OFC.

Study of Lack of Fingering in the Waterfront

The existence and connectivity of high-permeability material in a fluvial reservoir influences waterflooding processes. Indeed, between 80% and 95% of oil comes to a production well through the OFC cells even though the total proportion of OFC cells is from 16% to 28%. This is not a surprise because the mean permeability of OFC is 80 times larger than sandstone. This difference in permeability might be expected to produce: (1) highly developed fingering of the water-oil front and (2) a pronounced difference in dynamics between reser-

voir realizations, which include spanning OFC clusters and those without such clusters. However, Gershenzon et al. (2015; their figs. 9 and 11) showed that the oil production dynamics are not noticeably different between realizations with spanning OFC clusters (realizations 1–4) and those without spanning clusters (realizations 5 and 6) (see also Fig. 12). Moreover, the large-scale fingering of the water-oil front was not observed in any of the realizations. Indeed, as Figure 15 shows, the water-oil front is similar in each realization and has a relatively smooth shape, regardless of the value of the pressure gradient. These features can be explained by the specific structure of the fluvial-type reservoir

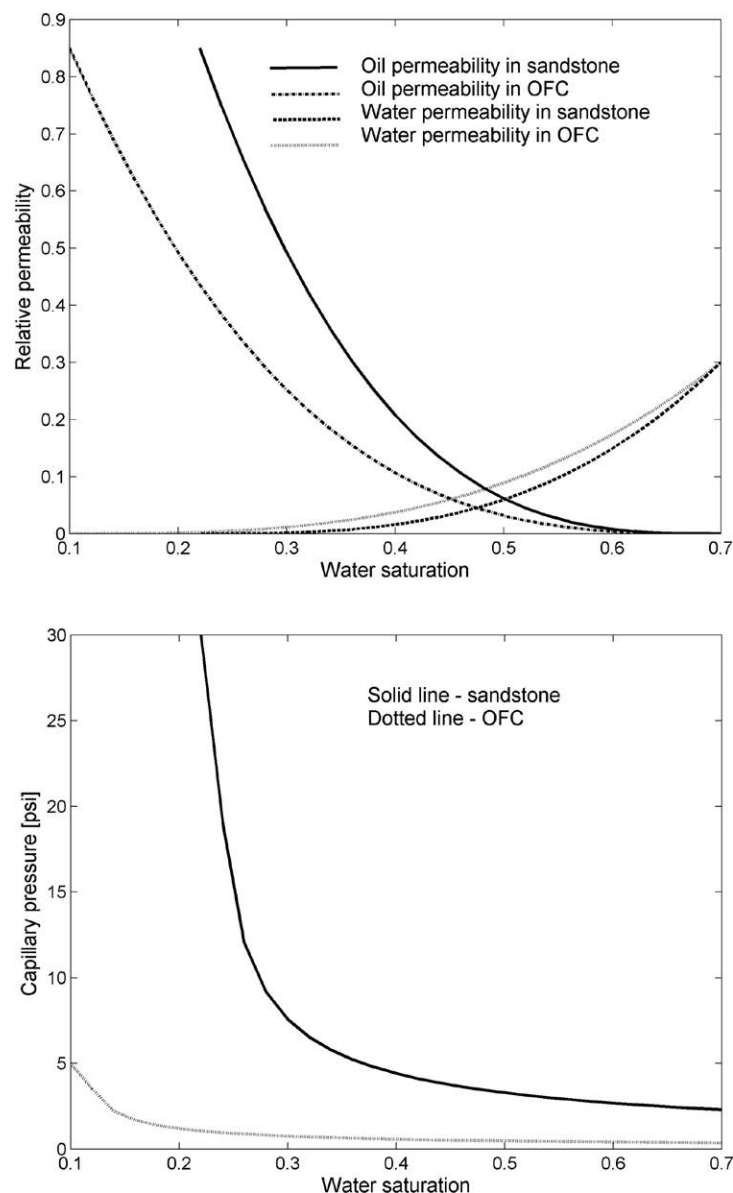


Figure 9. Capillary pressure and relative permeability of oil and water versus water saturation for sandstone and open-framework conglomerate (OFC) lithotypes.

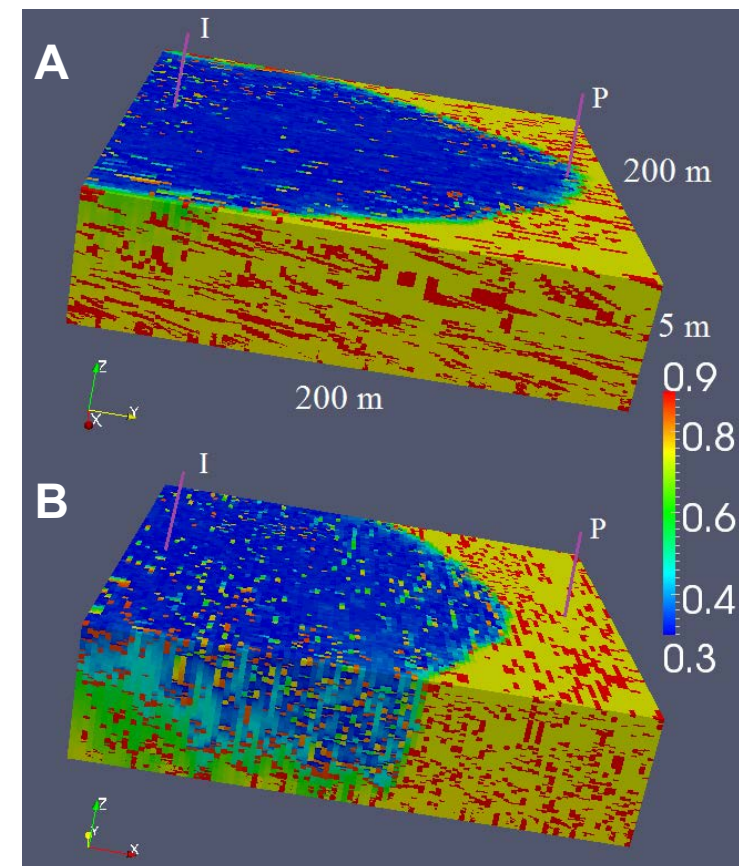


Figure 10. Oil-saturation distribution in reservoir realization 4 after 200 days of water injection. Pressure difference between wells is 100 psi. Paleoflow was left to right in (A) and front to back in (B). Pressure gradient is parallel (A) and normal (B) to paleoflow direction. The wells are perforated along total reservoir width.

as follows. Note that in all reservoir realizations (1) small distances separate OFC clusters (and different branches of the same cluster) in the vertical direction (from 35 cm to 55 cm; see Table 2, column 7); and (2) the branches of OFC clusters are thin in the vertical direction (~10–15 cm). Figure 16 illustrates the typical pattern of oil flow between such structures. Oil moves preferentially along the pressure gradient in high-permeability OFC clusters and diffuses preferentially in the direction normal to OFC branches in the low-permeability sandstone. Because the distances between OFC branches are small and because capillary pressure pushes oil from the sandstone to the OFC, oil from sandstone cells reaches the OFC cells relatively quickly (the pressure differ-

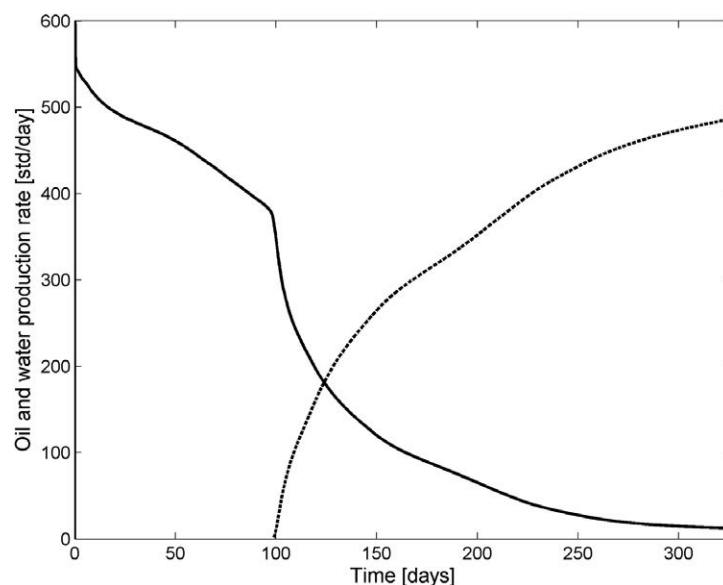


Figure 11. Oil (solid line) and water (dashed line) production rates versus time for realization 3. The pressure difference between the injector and producer wells is 200 psi, and the pressure gradient is along the y direction.

ence between injection and production wells ranged from 100 to 800 psi). This process and the small thickness of the OFC branches explain both the absence of the large-scale fingering and the fact that most of the oil reaches the production well through the OFC clusters. As can be shown, even realizations with a small proportion of OFC material include large-scale clusters (although there are no spanning clusters). The same scenario of oil movement (Fig. 16) works also for those realizations, which explains the almost identical behavior (from sweep efficiency point of view) of waterflooding in all reservoir realizations.

Study of Oil Trapping as a Function of the Pressure Gradient and the Proportion of OFC

The dynamics of immiscible oil displacement by water are described by the Buckley-Leverett equation (Buckley and Leverett, 1942). Solutions of this equation for homogeneous media and neglecting capillary pressure indicate that part of the oil (above irreducible oil saturation) remains behind the water-oil front. This is a fundamental origin of low oil-sweep efficiency during the process of immiscible oil displacement. Solutions of the Buckley-Leverett equation in heterogeneous media (also neglecting capillary pressure) show that heterogeneities may “trap” oil (Wu et al., 1993; Kaasschieter, 1999), which

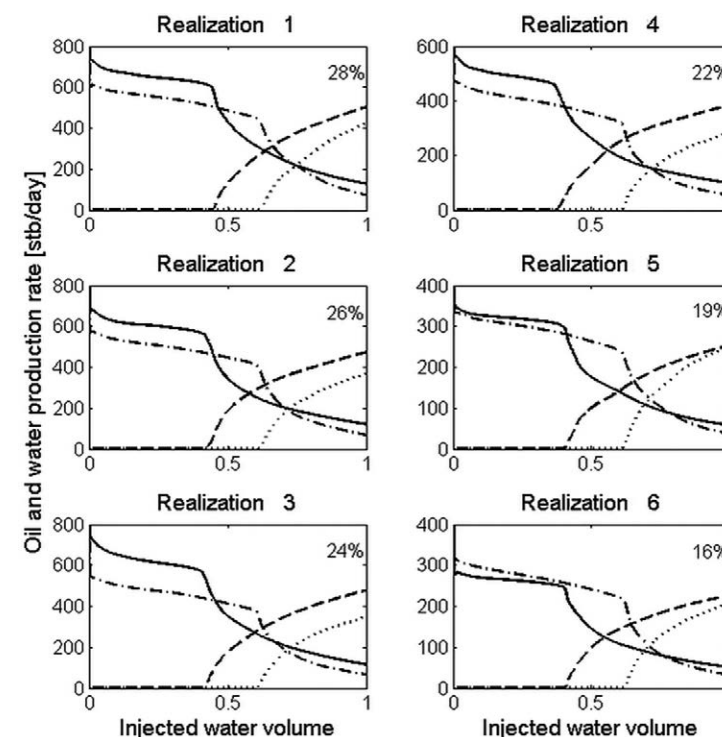


Figure 12. Oil and water production rates versus injected water volume for the six modeled realizations (Table 1) (the proportion of open-framework conglomerate [OFC] is shown at the top right-hand corner of each graph). The pressure difference between the injector and producer wells is 200 psi. The solid lines show the oil production rates when the pressure gradient is along the y direction; dashed lines show the water production rates when the pressure gradient is along the y direction; dot-dashed lines show the oil production rates when the pressure gradient is along the x direction; dotted lines show the water production rates when the pressure gradient is along the x direction. The injected water volume is normalized by the pore volume of the reservoir minus the irreducible water volume and residual oil saturation. From Gershenzon et al. (2015).

is an additional reason for the low oil-sweep efficiency. Analysis of the solutions in media with uniform permeability but heterogeneous capillary pressure revealed yet another mechanism of oil trapping (Kortekaas, 1985). The heterogeneities of various scales typical for the fluvial-type reservoirs add other complications to the process (Kjensvik et al., 1994; Tye et al., 2003; Choi et al., 2011). The interplay of the different mechanisms makes oil-sweep efficiency a complicated nonlinear function of the magnitude and direction of the pressure gradient (or velocity of the water-oil front) as well as the size, direction, and connectivity of heterogeneities in capillary pressure and permeability. Indeed, as our simulations show, the spatial and temporal distribution of oil saturation in fluvial-type reservoirs critically depends on those parameters.

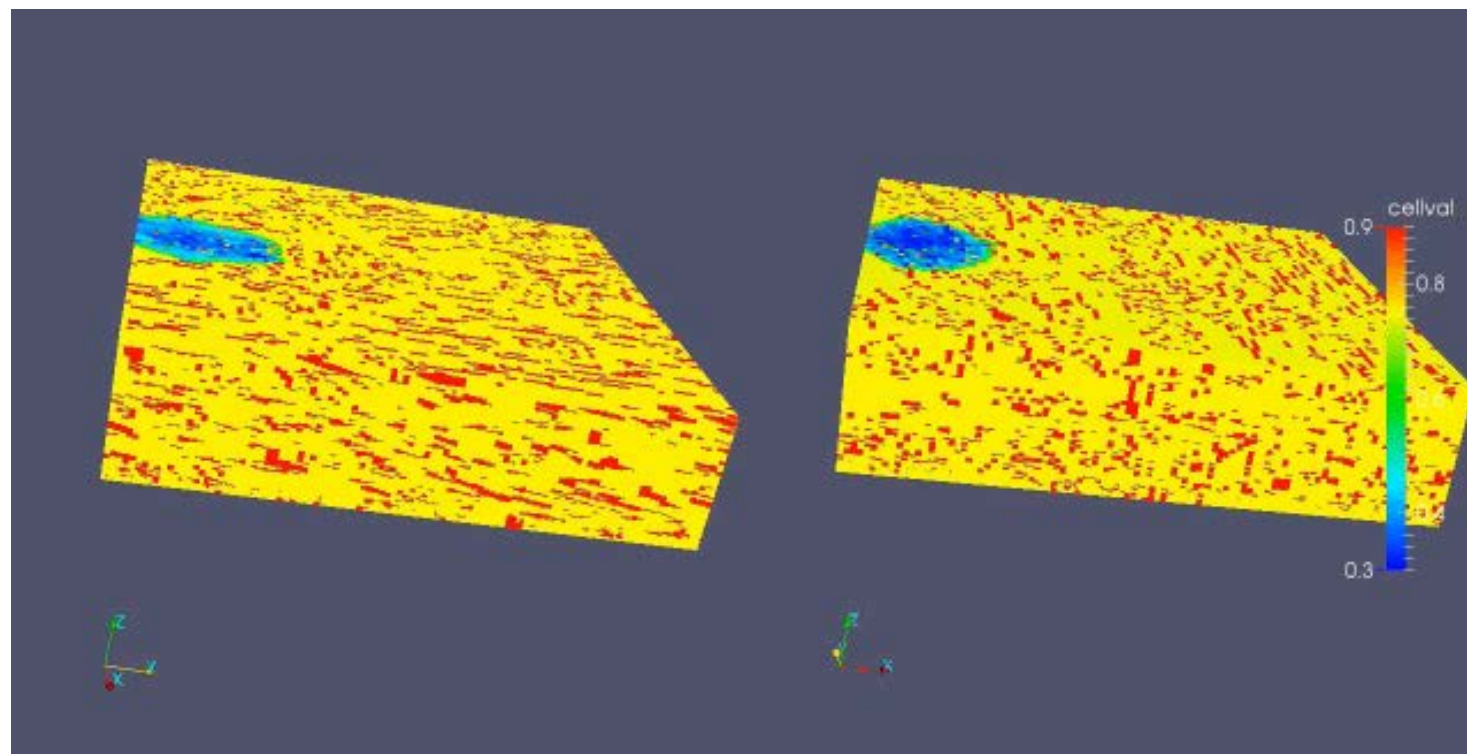


Figure 13. Animated oil-saturation distribution in reservoir realization 4 from the beginning of water injection up to 500 days. Pressure difference between wells is 100 psi, pressure gradient is parallel (a) and normal (b) to paleoflow (y) direction. To view the animation, please click on the figure in the PDF file of the paper, or visit <http://dx.doi.org/10.1130/GES01115.S1> or the full-text article on www.gsapubs.org.

TABLE 3. TOTAL OIL PRODUCTION NORMALIZED BY MOVABLE PORE VOLUME

Realization no.	Up to water breakthrough (y direction)	Up to water breakthrough (x direction)	Sweep efficiency ratio (between x and y directions) (%)	Up to injection of one movable pore volume water (y direction)	Up to injection of one movable pore volume water (x direction)
1	0.279	0.379	16.1	0.418	0.545
2	0.263	0.378	18.4	0.434	0.516
3	0.257	0.384	20.6	0.427	0.538
4	0.235	0.398	27.1	0.349	0.467
5	0.245	0.371	20.0	0.341	0.419
6	0.254	0.366	17.5	0.279	0.483

Note: The pressure difference between wells is 200 psi. We quantify sweep efficiency (SE) as the percentage of oil removed from a reservoir before water breakthrough: $SE = 1 - S_{break}$, where S_{break} is the resulting (after water breakthrough) oil saturation normalized by the initial movable oil volume S_{nit} . The ratio between sweep efficiency when the pressure gradient is in the x direction and when it is in the y direction presented in a fourth column.

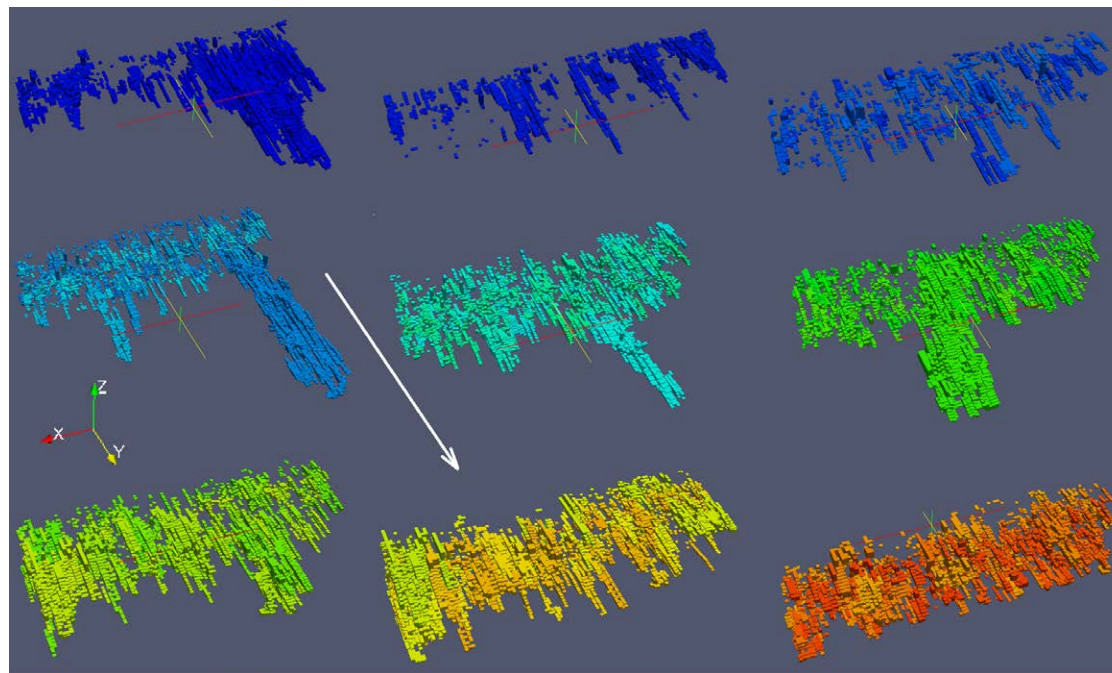


Figure 14. View of all (but spanning) open-framework conglomerate (OFC) clusters (total number of clusters is 8562) extracted from the 200:200:5 m domain of realization 4. Most of the clusters are elongate in paleoflow (y) direction. Clusters are arbitrarily assigned different colors. The white arrow shows paleoflow direction.

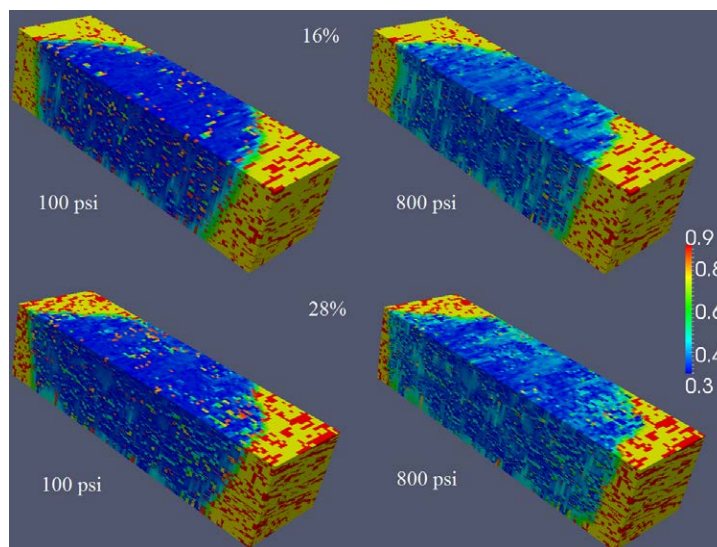


Figure 15. Oil-saturation distribution for the slices of reservoir 0:200 × 100:160 × 1:5 m for realizations 1 (bottom panels) and 6 (top panels). Pressure difference between wells is 100 psi (left panels) and 800 psi (right panels). Values of 16% and 28% indicate the percentage of open-framework conglomerate (OFC).

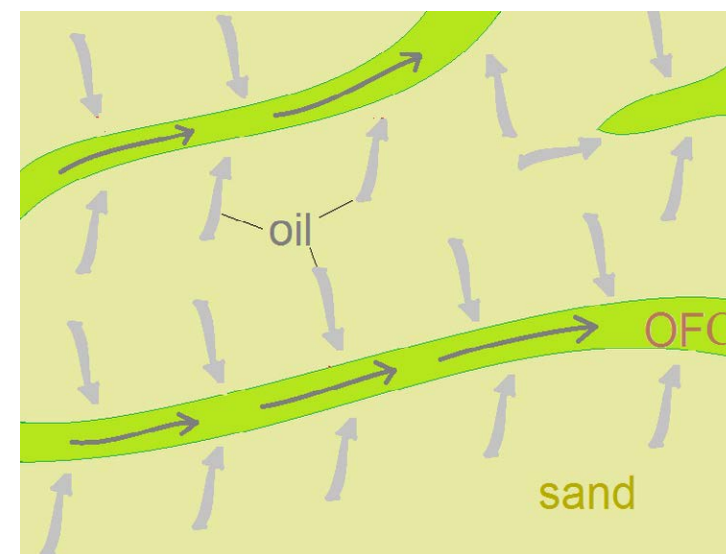


Figure 16. Image of oil-migration paths in fluvial-type reservoirs during waterflooding.

Corbett et al. (1992) modeled waterflooding in heterogeneous two-dimensional (2D) reservoirs. They found that sweep efficiency in such reservoirs depends on the pressure gradient. The amount of oil recovered was different by a factor of two for different values of the pressure gradient. This effect was due to the difference in the capillary pressure in different materials leading to oil trapping in material with smaller capillary pressure. The amount of oil locally trapped depends on the pressure gradient (ΔP) and the size of heterogeneity in the gradient direction (l). If the difference in capillary pressure between two materials is small compared to $\Delta P \cdot l$, the effect of capillary pressure is also small. In contrast, if this difference is larger than $\Delta P \cdot l$, the trapping effect is dominant. Therefore, in our simulations, the trapping effect is larger for the smallest OFC clusters, and there is no trapped oil in spanning OFC clusters (see Gershenson et al., 2015; their figs. 12 and 13). The opposite effect also occurs when oil from the material with large capillary pressure (sandstone in our case) is pushed by the capillary pressure into the material with low capillary pressure (OFC). As a result, oil saturation in sandstone is reduced. The interplay between these two effects defines the spatial and temporal distribution of oil in a process of oil displacement by water. Thus, oil-sweep efficiency is expected to depend on the pressure difference between injection and production wells, as has been concluded by Kortekaas (1985), Corbett et al. (1992), and Ringrose et al. (1993).

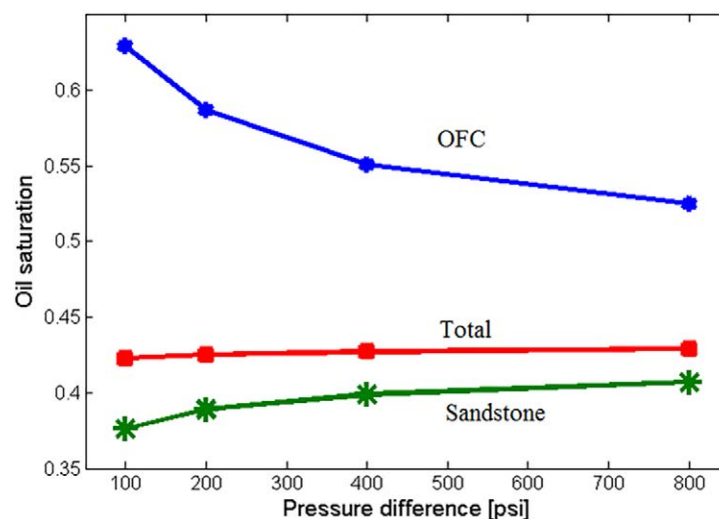


Figure 17. Oil saturation averaged over open-framework conglomerate (OFC) cells (blue), sandstone cells (green), and all cells (red) after injection of 1 water volume (in units of pore space volume minus volume of connate water and volume of irreducible oil) as function of pressure difference for realization 5. From Gershenson et al. (2015).

However, our analysis of simulations utilizing all six realizations revealed an unexpected result. In spite of the differences in the spatial distribution of oil for different pressure gradients, the integral parameters such as remaining oil saturation (hence oil-sweep efficiency) did not depend on the pressure gradient (see Fig. 17). This was true regardless of the direction of the pressure gradient (i.e., parallel or normal to paleoflow direction). The effect of oil trapping in OFC clusters is offset by the effect of oil reduction from the surrounding sandstone. This effect occurred regardless of whether the OFC material formed limited or spanning clusters and even regardless of whether or not a spanning cluster occurred in the reservoir. Figures 18 and 19 illustrate this result and support this conclusion. These figures show all cells within the reservoir having oil saturation in either of two different ranges at the same stage of the waterflooding process. Note that all cells with oil saturation in the range from 0.78 to 0.9 are the OFC cells because the irreducible saturation of the wetting phase (water) for the sandstone and OFC are different, at 0.22 and 0.1, respectively. Figures 18 and 19 show that the total amount of OFC cells having such saturation of trapped oil is visibly different for the different pressure gradients for both realizations 1 and 6 (see top panels of Figs. 18 and 19). These figures show that the amount of trapped oil in OFC clusters is larger if the pressure gradient is smaller. In contrast, the amount of oil remaining in sandstone cells is smaller when the pressure gradient is smaller (bottom panels of Figs. 18 and 19).

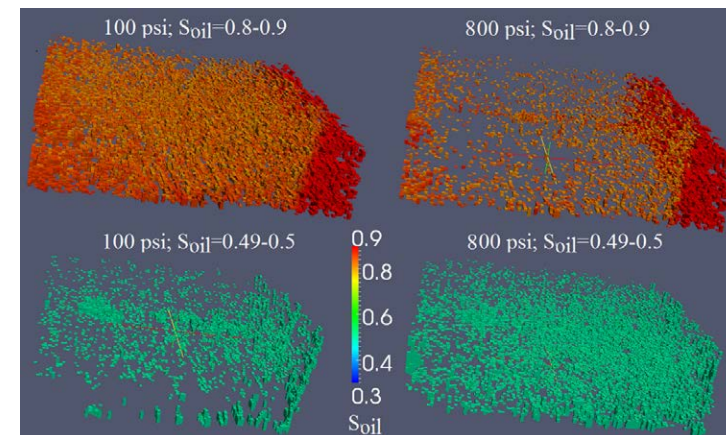


Figure 18. Cells with oil saturation in the range indicated at the top of each panel for the reservoir realization 6 (16% of open-framework conglomerate [OFC]) after waterflooding with pressure difference between injection and production wells of 100 psi (panels at the left) and 800 psi (panels at the right). The choice of intervals of oil saturation is arbitrary, i.e., 0.49–0.5 for sandstone and 0.8–0.9 for OFC. The intervals were chosen to make the effect more visible. The scale is 200:200:5 m.

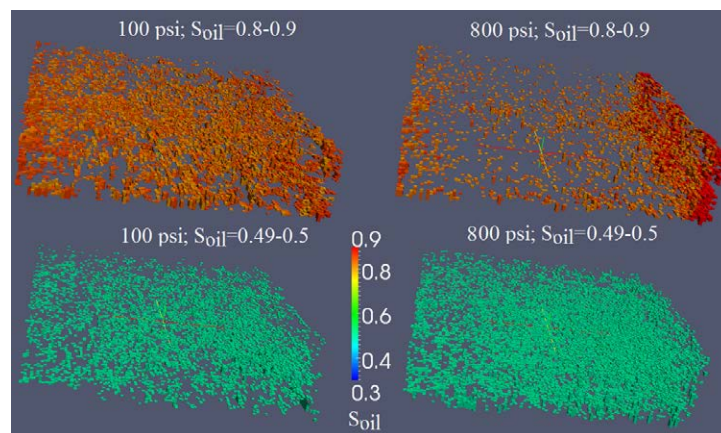


Figure 19. The same as on Figure 18 for the reservoir realization 1 (28% of open-framework conglomerate [OFC]).

CONCLUSIONS

The fluvial architecture represented here is not found in all reservoirs but is found in some very important ones (e.g., the Ivishak Formation, Prudhoe Bay Field, Alaska; see Stalkup and Crane, 1991; McGuire et al., 1994, 1999a; Tye et al., 2003). The basic model for hierarchical fluvial architecture used here (Lunt et al., 2004a; Bridge 2006) is fairly general and applies over a broad range of median grain size. Furthermore, the dimensions of unit types across the stratal hierarchy scale together with the width of the channels forming the deposit (Bridge, 2006). An important characteristic of coarser-grained reservoirs is that open-framework conglomerate strata are connected and impart higher-permeability pathways within the reservoir (Tye et al., 2003; Guin et al., 2010). These pathways cannot be imaged in 2D cross sections, and their effect on the flow field cannot be understood from 2D simulations (see Huang et al., 2012). To visualize and fully understand the impact of these connected flow pathways within a reservoir simulation requires advanced 3D visualization tools as used here.

Several features distinguish our approach to reservoir simulation from others:

- (1) The modeled heterogeneity structure and scales, hence permeability distribution, realistically reflect the typical fluvial-type reservoirs.
- (2) The size of reservoir heterogeneities ranges from a few centimeters to dozens of meters.
- (3) The reservoir contains two different materials: sandstone and open-framework conglomerate. These materials have different properties, requiring two sets of property curves for simulation.
- (4) Capillary pressure effects are utilized in the simulations.

By directly representing the smaller-scale cross-sets and their organization within bar deposits, the results allow a direct study of how they influence oil-trapping processes and hence the oil-sweep efficiency. The OFC cross-sets form connected clusters of different sizes, but as organized within bar deposits, the clusters typically have a larger extent in the paleoflow direction. This anisotropy affects the integral parameters of waterflooding such as water breakthrough time, cumulative oil production, and oil-sweep efficiency. Fingering on the water oil boundary might be expected for various reasons: 1) because of the large difference in permeability between OFC and sandstone; 2) because the size of some of the OFC clusters considerably exceeds the cell size in both horizontal and vertical directions; and 3) because the majority of oil reaches the production wells through OFC channels. However, large-scale (with typical scale much larger than horizontal cell size) fingering was not observed. We did observe different degrees of water-oil front diffusivity for the different reservoir realizations and different pressure gradients, which could be considered as small-scale fingering. Large-scale fingering is absent because the width in vertical direction of the sandstone layers between OFC channels is small, so there is enough time for oil to diffuse from the sandstone to OFC channels, unless the pressure gradient is extremely large.

The content, structure, and connectivity of high-permeability material in a fluvial reservoir affect both oil production rate and water breakthrough time. However, oil-sweep efficiency is not practically affected by the proportion and degree of connectivity of high-permeability beds. The most surprising finding of our 3D simulations is the independence of oil-sweep efficiency from the pressure gradient in all considered realizations and directions of the pressure gradient. This is even more surprising if we keep in mind the highly nonlinear character of waterflooding processes. The amount of oil trapped in OFC, which decreases with increase of pressure gradient, is compensated by the amount of remaining oil in sandstone, which increases with increase of pressure gradient, in such a way that the total amount of remaining oil does not depend on the pressure gradient. This “self-regulating process” could be understood in terms of small-scale and dense networks of OFC cells. Thus, oil-sweep efficiency is not affected by the pressure gradient although the spatial distribution of residual oil critically depends on this value.

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