Reservoir-scale characterization and multiphase fluid-flow modelling of lateral petrophysical heterogeneity within dolomite facies of the Madison Formation, Sheep Canyon and Lysite Mountain, Wyoming, USA

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ABSTRACT: Carbonate reservoirs often exhibit complex pore networks and various scales of petrophysical heterogeneity associated with stratigraphic cyclicity, facies distribution and diagenesis. In addition, petrophysical variability also exists within distinct rock fabrics at the interwell scale. Data from lateral transects through dolomitized carbonates of the Mississippian Madison Formation in north and central Wyoming exhibit three scales of lateral petrophysical variability. These include a near-random component (nugget effect), short-range variability and a long-range periodic trend (hole effect) that is observed in both dolowackestone (Sheep Canyon) and dolograinsone (Lysite Mountain) facies. The dolowackestone represents outer and middle ramp mud-supported fabrics, while the dolograinstone represents amalgamated skeletal and oolitic shoals.

Detailed 3D petrophysical models of the dolomite facies and 2D multiphase waterflood simulations explore the effects of this heterogeneity on reservoir performance through several model scenarios. Fingering of the injected fluid front, sweep-efficiency, breakthrough time and bottom-hole well pressures are sensitive to lateral reservoir heterogeneity and rock fabric. Models with greater short-scale continuity of petrophysical properties have higher degrees of large-scale fingering, higher sweep efficiency and shorter breakthrough times. The reservoir performance of the dolowackestone differs from the dolograinstone for those models that exhibit a specific range of short-scale heterogeneity. In general, the dolowackestone has a higher degree of both small- and large-scale fingering, lower sweep efficiency and longer breakthrough time compared with the dolograinstone.

Intra-facies scale variability is significant in regard to reservoir performance and is often difficult or impossible to determine from typical subsurface datasets. Information from outcrop analogues is necessary to create conceptual 3D geological models and to begin to quantify interwell heterogeneity within dolomite reservoirs.

KEYWORDS: Madison Formation, heterogeneity, dolomite, reservoir

INTRODUCTION
Carbonate reservoirs often exhibit a high degree of lithologic and petrophysical heterogeneity related to the sequence-stratigraphic framework, distribution of depositional facies and diagenetic alteration. To describe this heterogeneity for reserves estimates and field development, detailed reservoir characterization and modelling are necessary. Well, seismic and core data typically are sufficient to delineate the seismic-scale sequence-stratigraphic framework, identify high-frequency or metre-scale cycles and flow units and characterize lithofacies and petrophysical characteristics close to the borehole. However, lateral petrophysical heterogeneity exists at the sub-seismic scale, even within what are typically considered flow units. Capturing this interwell-scale petrophysical variability in reservoir models is important for accurate rock and fluid volume estimates and reservoir performance predictions. Estimates of lateral petrophysical variability, however, are very limited because these data typically do not exist in subsurface datasets. Outcrop analogues of subsurface carbonate reservoirs provide an understanding of this scale of heterogeneity within similar lithofacies and equivalent reservoir flow units and are used to augment subsurface datasets (e.g. Eisenberg et al. 1992; Kerans et al. 1994).

Previous studies have investigated lateral reservoir-scale petrophysical heterogeneity within carbonate lithofacies on outcrops of the Permain San Andres Formation of West Texas and New Mexico (Kittridge 1988; Kittridge et al. 1990; Senger et al. 1991; Eisenberg et al. 1992; Lucia et al. 1992; Ferris 1993; Kerans et al. 1993, 1994; Grant et al. 1994; Wang et al. 1994; Barnaby et al. 1997; Jennings et al. 2000) and, more recently, in the Mississippian Madison Formation of north-central Wyoming (Pranter et al. 2005). Most of these studies show that within individual dolomite rock-fabrics, approximately 50% of the variance in permeability appears random (the nugget effect, Eisenberg et al. 1994). The balance of the variability is...
characterized by a short-range correlation structure (typically <20 ft; 6 m). In the San Andres Formation datasets (Lawyer Canyon), two long-range, low magnitude, periodic trends in the permeability data were also observed, with wavelengths of 140–180 ft (43–55 m) and >1000 ft (305 m) (Jennings 2000).

Jennings et al. (2000) and Pranter et al. (2005) modelled the impact of lateral permeability variability (porosity was constant in all models) using tracers and single-phase fluid flow, respectively. These studies were based on data from porous dolomites of the San Andres and Madison formations, respectively. The results of both studies suggested that short- and long-range variability in permeability affects reservoir performance, especially the nature of the tracer front and breakthrough time.

This study further addresses the impact of interwell-scale lateral variability on dolomite reservoir quality and performance by using porosity as well as permeability data from outcrops, and by addressing multiphase fluid flow. Another important aspect of this study is the direct use of experimental semivariograms in heterogeneity modelling instead of variogram models generated from experimental semivariograms. Three specific questions were addressed.

1. What is the character of lateral heterogeneity in reservoir-quality dolomite rock fabrics? How much of the variability is represented by a nugget effect? What is the short-range variability? Does a long-range heterogeneity trend exist in the dolomites?
2. What is the impact of the different components of the lateral petrophysical heterogeneity on multiphase fluid flow? Specifically, what is the impact of the nugget effect and short-range variability on fluid-flow parameters? How are the fluid-flow parameters affected by different rock fabrics?
3. Which fluid-flow variables are sensitive (or insensitive) to the different components of lateral petrophysical heterogeneity?

To answer these questions, well-exposed dolomite outcrop analogues were sampled, petrophysical properties of the samples were measured, variography and 3D heterogeneity modelling were conducted, 2D multiphase fluid-flow (water-flood) simulations were performed on the heterogeneity models and the fluid-flow response was evaluated.

**STUDY AREA AND STRATIGRAPHIC FRAMEWORK**

This study focuses on dolomitized facies from well-exposed outcrops of the Mississippian Madison Formation in north and central Wyoming. Petrophysical sampling and analyses, porosity and permeability heterogeneity modelling and fluid-flow simulations were conducted using data from exposures of porous and permeable units in the Madison Formation at Sheep Canyon and Lysite Mountain, Wyoming (Fig. 1). The outcrops at Sheep Canyon are located approximately 5 miles (8 km) northeast of Greybull, Wyoming in the Bighorn Basin. The Bighorn River flows to the northeast through Sheep Canyon and exposes nearly the entire Madison Formation. Lysite Mountain is located approximately 40 miles southeast of Thermopolis, Wyoming in the Owl Creek Mountains (Fig. 1). The Madison Formation outcrops at Sheep Canyon and Lysite Mountain and the equivalent Madison subsurface formations exhibit similar rock fabrics and petrophysical properties (Crockett 1994; Moore 2001; Pranter et al. 2005) and are analogous to other Palaeozoic shelf carbonates and associated reservoirs (Sonnenfeld 1996; Eberli et al. 2000; Westphal et al. 2004).

The Madison Formation was deposited in a broad marine ramp environment that covered the area that is now New Mexico to western Canada (Sando 1976). The Madison Formation represents a single second-order stratigraphic sequence (approximately 12–13 Ma duration) bound at the top and base by regionally extensive, tectonically induced unconformities or sequence boundaries (Sonnenfeld 1996). The second-order sequence is subdivided into six third-order sequences in northern Wyoming (sequences I–VI), which are further subdivided into intermediate- and small-scale depositional cycles (Fig. 2; Sonnenfeld 1996). Sonnenfeld (1996) also recognized what are defined as lower (sequences I and II) and upper (sequences III–VI) third-order composite sequences (Fig. 2).

At Sheep Canyon, all six third-order sequences are exposed. Sequence I was the focus of detailed measurements because of its reservoir-quality porosity and accessibility. Regionally, sequence I is interpreted to have been deposited on a ramp profile with updip restricted lagoonal facies overlain and grading downdip into shoreface/shoal grain-supported fabrics that in turn overlay and grade downdip into outer and middle ramp mud-supported fabrics (Sonnenfeld 1996). At Sheep Canyon, Sequence I is dominated by the later two facies tracts. At Lysite Mountain, only four of the six third-order sequences (sequences I–IV) are present (Crockett 1994; Sonnenfeld 1996). Sequences V and VI were removed by mid- and post-Mississippian erosion (Sando 1976; Sandberg & Klapper 1967). Sequence II, the focus of the sampling at Lysite Mountain, represents inner ramp shelfface depositional conditions (Sonnenfeld 1996; Moore 2001; Westphal et al. 2004). Sequence II exhibits high-frequency cycles dominated by laminated dolomudstones and dolowackestones at the base that transition into dolowackestone cycles (transgressive systems tract) followed by high-energy cross-bedded and amalgamated ooid and bioclastic dolocarbonate cycles (highstand systems tract) near the top of the sequence (Moore 2001; Westphal et al. 2004). The amalgamated dolocarbonate units in sequence II have minor thickness variation but are laterally continuous across the outcrop at Lysite Mountain.

Crockett (1994), Sonnenfeld (1996) and Moore (2001) advocated early dolomitization of sequences I–III by refluxing, hypersaline brines. The dolomitization was primarily fabric

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**Fig. 1.** Location of the Sheep Canyon and Lysite Mountain study areas, Wyoming, USA (modified from a United States Bureau of Land Management illustration).
destructive and generated intercrystalline and moldic pore types.

**DATA SAMPLING AND MEASUREMENTS**

Within the Madison Formation and many carbonate reservoirs, the effects of diagenesis overprint the stratigraphic framework and primary petrophysical properties to create a complex pore network and permeability distribution. Reservoir assessment based on vertical well data or vertical measured sections from outcrop analogues is limited for these carbonate systems where it is important to characterize and quantify the complex interwell reservoir quality. To begin to assess lateral reservoir heterogeneity using outcrop data, well-sampled lateral transects across key reservoir facies or flow units are needed. This information on lateral petrophysical variability is necessary in reservoir characterization and modelling and is generally unavailable from subsurface datasets.

To analyse and quantify interwell-scale petrophysical heterogeneity within dolomite rock fabrics of the Madison Formation, a dataset from regularly spaced rock samples was acquired along several lateral and vertical transects. The dataset consists of 1745, one-inch diameter core plug samples and their respective petrophysical property measurements. Samples were obtained with a water-lubricated core drill at a 1 ft (30 cm) spacing. A 1 ft (30 cm) sample spacing was used based on the results of Eisenberg et al. (1994), who estimated that this spacing was appropriate to capture reservoir-scale variability within dolomite rock fabrics. Lateral variability also exists below the 1 ft scale (e.g. pore-scale variability) within dolomite reservoirs; however, this study focused on those lateral reservoir-scale heterogeneities that exist at a scale of 1 ft and larger.

Data from two lateral transects are the focus here. These transects include one from Sheep Canyon (SC) that was obtained in sequence I and one from sequence II at Lysite Mountain (LM). Lateral transect SC is located at the core of the exposed anticline within Sheep Canyon (Fig. 3) and is 483 ft (147 m) in length. Transect SC targeted a bioturbated, skeletal dolowackestone/mudstone facies of the transgressive systems tract of sequence I. This outer ramp facies is one of the most porous of all rock fabrics exposed at Sheep Canyon (Sonnenfeld 1996; Smith et al. 2004). Transect LM is 495 ft (151 m) in length and located in a well-exposed, laterally continuous cross-bedded dolograinstone unit (Fig. 3). Both the dolowackestone and dolograinstone exhibit porosity and permeability associated with intercrystalline and moldic pore networks.

Core plug samples were trimmed to lengths of approximately 1–1.5 in (2.5–3.8 cm). The outer 0.5–0.75 in (1.27–1.9 cm) of each sample was trimmed and not used for petrophysical analyses to avoid errors associated with outcrop weathering and sampling methods. Permeability measurements were made...
using a mini-probe permeameter (MPP). The MPP measures the flow of nitrogen gas through a rock sample at a set range of injection pressures. Flow rates were converted to permeability based on empirical calibrations from a set of standard core plugs with known permeabilities. Calibration of the standard plugs was run daily to account for any changes in atmospheric pressure. Because of the small scale of investigation of the MPP, the geometric mean permeability was calculated using up to four permeability measurements, two on each end of the plug. This was done to minimize the effect of intra-sample variability. Horizontal permeability values were measured for each cylindrical core plug and for the same orientation. Therefore, petrophysical anisotropy was not considered. Further details as to the mini-permeameter procedures that were utilized can be found in Budd (2001). Porosity was measured for each sample using a modification of the bulk-density technique (Singer & Janitzky 1986).

PETROPHYSICS AND LATERAL VARIABILITY

Short-range variability and a longer-range cyclicity is evident in porosity and permeability data for the Sheep Canyon (SC) and Lysite Mountain (LM) lateral transects (Fig. 4). The mean and standard deviation for porosity and permeability in the SC transect are 17.4% and 3.3% and 40.5 mD and 46.4 mD, respectively. For the LM transect, the mean and standard deviation of porosity and permeability are 16% and 4.0% and 73.4 mD and 74.3 mD, respectively. The dolowackestones at Lysite Mountain are comparatively more permeable than the dolowackestones at Sheep Canyon; however, the grainstones have a lower mean value for porosity (Fig. 5). In addition, the variances in porosity and permeability for the dolowackestones are lower than those for the dolostones. Despite the higher variance for the dolostones, the correlation coefficient between porosity and permeability is higher for the grainstones ($r^2=0.75$) versus the wackestones ($r^2=0.62$) (Fig. 6).

Semivariograms of these petrophysical parameters exhibit pronounced short-range variability and different scales of a longer-range cyclicity or periodicity (Fig. 7). For all
semivariograms, the data have been transformed using normal-score transformations. The semivariograms are generated using a lag interval of 1 ft (0.3 m) to coincide with the sample spacing. The number of lags used for Sheep Canyon and Lysite Mountain are 460 and 475, respectively. To produce statistically significant variance values, a lower limit of 20 data pairs was used for a given variance calculation. The idea is to retrieve as much information as possible on the spatial petrophysical property distribution and its persistence.

More than 50% of the petrophysical variability is represented by random effect (nugget effect). The precise nugget-effect values for dolowackestone are 58% and 65% for porosity and permeability, respectively, and those for dolograinstone are both 55%. Apart from the nugget effect, there exists a short-range variability. The semivariogram range (correlation length) values for dolowackestone are about 13 ft (4.0 m) and 22 ft (6.7 m) for porosity and permeability, respectively. In the dolograinstone, the short-range semivariogram ranges for porosity and permeability are both 15 ft (4.6 m). Short-range periodicities (hole effects) are also pronounced on all semivariograms (Fig. 7). The dolowackestone short-range periodicity is approximately 25–40 ft (7.6–12.2 m) for porosity and 15–30 ft (4.6–9.2 m) for permeability. Dolograinstone short-range periodicities are 15–30 ft (4.6–9.2 m) and 15–40 ft (4.6–12.2 m) for porosity and permeability, respectively. For the dolograinstones at Lysite Mountain, a long-range periodicity is also pronounced. This distinct periodicity is approximately 80–120 ft (24.4–36.6 m) for both porosity and permeability data. Although less distinct, the long-range periodicity is exhibited on the dolowackestone semivariograms (Fig. 7), with a wavelength of approximately 100–150 ft (30.5–45.7 m) for porosity. This higher-order periodicity in the dolowackestone permeability data is apparent but less pronounced, with a wavelength of less than 100 ft (30.5 m).

HETEROGENEITY MODELS

The detailed sampling and variography unveils the multi-scale lateral variability of petrophysical properties in dolomite facies and reservoirs. This is significant because lateral petrophysical variability cannot be recognized or determined from vertical well data or vertical measured sections. Reservoir models based on just vertical data will not capture the lateral heterogeneity. It is especially important to determine and incorporate the lateral short-range petrophysical variability. This scale of variability relates directly to the overall lateral petrophysical heterogeneity within the dolomite facies. Because the lateral variability is further confounded by a non-constant periodicity, the structured semivariogram models that are commonly used in reservoir heterogeneity modelling do not honour the data adequately. For this reason, the use of covariance look-up tables (of the corresponding semivariogram) that are generated outside the stochastic simulation modules is rationalized. The covariance look-up tables are simply a tabular form of the
seminvariograms, that is the tables that consist of lag distances and the corresponding semivariogram values. The stochastic simulation program uses the values from this table to estimate (or simulate) the unknown parameters of interest (e.g. porosity).

Different scenarios for petrophysical heterogeneity modelling of the dolomite facies were explored. For the first scenario, it was assumed that detailed petrophysical data were from vertical wells and that detailed information on the lateral variability did not exist. In this scenario, geometric mean porosity and permeability values were assigned for the dolowackestone and dolograinstone heterogeneity models. This scenario represents a base case for comparison with the other heterogeneity model scenarios and is not used as an upscaled model. For the second scenario, covariance look-up tables are used in the simulation of porosity and permeability (or more precisely, in kriging within the simulation process) based on the 5-point moving average of the sampled semivariograms of the dolowackestone and dolograinstone transects. The third scenario evaluates the importance of the correct short-range lateral variability by using a heterogeneity model that honours the longer-range periodic trend for the dolowackestone but has a larger range for the short-scale petrophysical variability. Finally to determine the impact of the nugget effect, the fourth scenario is a heterogeneity model that uses the long-range structures of the third scenario but with zero nugget effect. For all stochastic simulations, the sequential Gaussian simulation method was employed (Deutsch & Journel 1997).

For the four scenarios, different heterogeneity models were explored, each investigating fluid-flow behaviour within a single flow unit composed of one dolomite fabric. These are enumerated and labelled below for subsequent referencing in this paper (1, 2, 3, 4 for the scenarios; DW and DG for the rock fabric):

- a model of dolowackestone heterogeneity using experimental variogram and statistics (DW1);
- a model of dolowackestone heterogeneity using the experimental variogram and statistics (DW2);
- a synthetic model of dolowackestone heterogeneity using an experimental variogram and statistics but with a larger range for the short-scale structure (DW3);
- a synthetic model of dolowackestone heterogeneity using an experimental variogram and statistics but with a larger range for the short-scale structure and zero nugget effect (DW4);
- a model of dolowackestone heterogeneity using average values for porosity and permeability (DG1);
- a model of dolowackestone heterogeneity using an experimental variogram and statistics (DG2);
- a synthetic model of dolowackestone heterogeneity using an experimental variogram and statistics but with a larger range for the short-scale structure (DG3);
- a synthetic model of dolowackestone heterogeneity using an experimental variogram and statistics but with a larger range for the short-scale structure and zero nugget effect (DG4);
- a model of dolograinstone heterogeneity using the experimental variogram and statistics (DG1);
- a model of dolograinstone heterogeneity using experimental variogram and statistics but with a larger range for the short-scale structure and zero nugget effect (DG2);
- a model of dolograinstone heterogeneity using experimental variogram and statistics but with a larger range for the short-scale structure and zero nugget effect. Semivariograms for the dolograinstone porosity for the (a) original data, (b) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and (c) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and zero nugget effect. Semivariograms for the dolowackestone porosity for the (d) original data, (e) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and (f) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and zero nugget effect. Semivariograms for the dolograinstone porosity for the (g) original data, (h) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and (i) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and zero nugget effect. Semivariograms for the dolowackestone permeability for the (j) original data, (k) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and (l) original data but with a larger range (50 ft [15.2 m]) for the short-scale structure and zero nugget effect.

Scenario 2 models represent the actual lateral variability observed in outcrop and are ‘reservoir-specific’ for the dolomites at Sheep Canyon and Lysite Mountain, Wyoming. However, the rock fabrics and associated scales of variability that were observed in these Palaeozoic shelf carbonates are analogous to dolomite reservoirs of various ages (Sonnenfeld 1996; Eberli et al. 2000). Scenarios 3 and 4 models represent different petrophysical variability cases that could occur in dolomite reservoirs. Porosity and permeability input variogram values for the covariance look-up tables that are fed into the Gaussian simulator are displayed in Figure 8 for each of these models.

Unconditional simulations were used to capture the patterns of the lateral variability by directly using the experimental variogram values in the modelling. The outcrop face was not modelled explicitly. Three-dimensional petrophysical models were generated that incorporated the observed patterns of variability. Unconditional 3D Gaussian simulations are performed using a 5-layer model, with a relatively fine grid of 1000 × 1000 × 5 cells (in x-, y- and z-directions of a Cartesian grid system). Each cell dimension is 1 × 1 × 10 ft (0.3 × 0.3 × 3 m). The simulation domain has five million grid cells and covers a total area of 1.0 × 10^6 ft^2 (9.0 × 10^4 m^2) and a thickness of 50 ft (15.2 m). A range of detailed heterogeneity models was initially produced in which the number of previously simulated nodes varied within a range of 10 to 100, and the search radius isotropically varied from 50–400 ft.
The criteria used to select the heterogeneity models for fluid-flow simulation included the quality of histogram reproduction in Gaussian space and the limited frequency of extreme values. The simulated values in the Gaussian domain were back-transformed into the original space.

The number of grid cells (five million) used in the detailed heterogeneity models is too large for practical fluid-flow simulation. One can employ an upscaling procedure to coarsen the models for fluid-flow simulation, but the approach used will have varying impacts on the resulting scaled models. The scaling process should not mask the impact on the fluid flow of the lateral petrophysical variability observed in outcrop (i.e. the ground “truth”). Thus, it was decided to use smaller subsets of the heterogeneity models, each extracted from the five million cell models. These subsets were sufficiently large to preserve the lateral variability statistics, but small enough to conduct fluid-flow simulation within a reasonable timeframe. Because the wavelength of the long-range periodicity is approximately 100–150 ft (30.5–45.7 m) and the horizontal dimensions of the subset models are 500 × 500 ft (152 × 152 m), both the short- and long-range periodicities are captured. Some initial fluid-flow simulations of the models were performed and it was determined that subset models with 500 × 500 × 1 grid cells (250,000 total cells) and a cell size of 1 × 1 × 50 ft (0.3 × 0.3 × 15.2 m) would be appropriate for flow simulation. These extracted heterogeneity models are not upscaled and maintain the horizontal grid size of the original static heterogeneity models. The subset models were extracted in an unbiased manner from the central 500 × 500 cells (aerially). Extracted porosity and permeability models for each of the scenarios that were used in fluid-flow simulations are shown in Figures 9 and 10, respectively.

**FLUID-FLOW SIMULATION**

Two-phase oil–water fluid-flow simulation was investigated using a quarter five-spot injection–production pattern using ECLIPSE (GeoQuest 2004) reservoir simulation software. The producer and the injector were located in diagonal corners (quarter of five-spot pattern) of the heterogeneity models. The primary goal of the fluid-flow simulation exercise was to investigate the impact of the lateral petrophysical variability within the dolomites on fluid-flow responses. A simple and common reservoir-engineering problem involving waterflood was used for this fluid-flow simulation exercise. Because the emphasis of this study is on lateral petrophysical variability, the dataset consists of detailed lateral measurements and, to have reasonable simulation run times (most simulations ran for 20 hours), 2D simulations were used to address the impact of the lateral variability on fluid flows.

Fluid parameters used in the flow simulations are presented in Figure 11. The parameters that were considered include water relative permeability and oil–water capillary pressure for varying water saturation (Fig. 11a), two-phase oil relative permeability for varying oil saturation (Fig. 11b) and oil formation volume factor and oil viscosity for varying oil-phase pressure (Fig. 11c). Minimal complexities associated with fluid-flow phenomena are intended and the fluid properties are thus kept simple. We used a connate water saturation of 21% and initial water saturations were equilibrated to this value, with approximately 79% of the pore volume occupied by the oil phase. The residual oil saturation was about 28% (Fig. 11b). Initial well rates, reservoir pressure, fluid density and other parameters for the fluid-flow simulation are presented in Table 1. The initial pressure distribution was maintained at 3500 psi (2.4 × 10^7 Pa). Oil–water and gas–oil contacts were set below and above the reservoir model interval, respectively, and thus have no influence on the flow. Isotropic permeability in x- and y-directions was used. Initially, flow from the producer well was controlled by a maximum allowable flow rate (sometimes referred to as rate control mode). With pressure decline, flow from the producer was controlled by a minimum bottom-hole pressure (sometimes referred to as pressure control mode). Flow through the injector well was controlled by either a maximum injection flow rate (rate control mode) or maximum bottom-hole pressure (pressure control mode) depending on the well injectivity (Table 1).

Fluid-flow simulations were run to at least water breakthrough at the production well because the simulation run time was relatively high (>20 hours for each run) given the number of cells, and the primary focus was on pre-water-breakthrough behaviour. Fluid-flow variables investigated for the eight heterogeneity models are oil production rate, cumulative oil production volume, water injection rate, cumulative water injection volume, producer and injector bottom-hole pressures, watercut at the producer, ratio of oil production rate to water injection rate (Figs. 12a–b), water saturation distribution (Fig. 13), sweep efficiency (Fig. 14a) and breakthrough time (BTT) (Fig. 14b).
The oil production rate (Fig. 12a) of model DW4 exhibits an anomaly at an early time because in the vicinity of the producer, the petrophysical properties are relatively low (low transmissibility and porosity). This anomaly is also reflected on the bottom-hole pressure and the ratio of production-to-injection rate (Figs 12e and h). For similar reasons, model DW3 has a similar early time anomaly that occurs in the injector rate (Fig. 12c) and is also present on the injector bottom-hole pressure and the ratio of production-to-injection rate (Figs 12f and h). The late decline in oil production rate (Fig. 12a) is most likely due to excessive water production and the mechanics in the simulator that constrains the bottom-hole pressure. Injection flow-rate profiles (Fig. 12c) reveal that, except for DW3, all models have good injectivity and maintain rate control mode. For models DW1, DG1, DG3 and DG4, watercut increases rapidly after breakthrough. Watercut (Fig. 12g) for models DW2, DW3, DW4 and DG2 increases more gradually after breakthrough. To some extent, the correlation length and the range of permeability values influence this flow behaviour.

There is little variability in cumulative oil production and water injection (Figs 12b and d). The pattern of dolomite heterogeneity does not impact these parameters except for the minimal spread in cumulative oil production and water injection curves (Figs 12b and d).

Large variations are observed in the profiles of producer- and injector bottom-hole pressures (Figs 12c and f). The dolograinstone models (DG) have lower producer bottom-hole pressures and higher injector bottom-hole pressures relative to the dolowackestone models (DW). This is most likely due to the differences in the petrophysical properties, especially permeability, between the dolowackestone and dolograinstone. The spread between the bottom-hole pressure curves is related to the differences in heterogeneity between the models. This is directly due to the differences in correlation length of the short-range variability and the magnitude of the nugget effect. The models DW1 and DG1 (using geometric mean values) tend to produce at a higher bottom-hole pressure (Fig. 12c) compared with other heterogeneity models.

Water saturation maps (Fig. 13) indicate differences in the degree of fingering of the injected fluid front within the
Table 1. Parameters used in reservoir flow simulation

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<td>Injector grid cell</td>
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<td>Minimum injector bottom-hole pressure, psi [Pa]</td>
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Fig. 12. Flow response variables: (a) oil production rate; (b) cumulative oil production volume; (c) water injection rate; (d) cumulative water injection volume; (e) producer bottom-hole pressure; (f) injector bottom-hole pressure; (g) watercut; (h) ratio of oil production rate to water injection rate. DW1, based on Sheep Canyon dolowackestone geometric mean; DW2, based on Sheep Canyon dolowackestone original data; DW3, based on Sheep Canyon dolowackestone original data but with a longer range; DW4, based on Sheep Canyon dolowackestone original data but with a longer range and zero nugget; DG1, based on Lysite Mountain dolograinstone geometric mean; DG2, based on Lysite Mountain dolograinstone original data; DG3, based on Lysite Mountain dolograinstone original data but with a longer range; DG4, based on Lysite Mountain dolograinstone original data but with a longer range and zero nugget.

Discussion

Value of outcrop analogues

Although the value of outcrop analogues of reservoir facies has been increasingly recognized relative to siliciclastic deposits (e.g. Willis & White 2000; Grammer et al. 2004, several chapters; Castle et al. 2004; Pringle et al. 2004 and many more), such an approach has been applied only sparingly to carbonates. When applied, it has in fact focused more on...
reservoir-scale stratigraphic architecture than lateral petrophysical variability (e.g. Kerans et al. 1994; Tinker 1996; Grammer et al. 1996). Perhaps this is because carbonate outcrops are often presumed to be affected by recent exposure diagenesis or to exhibit diagenetic histories dissimilar from reservoir equivalents. The laterally extensive and thick regressive dolograinstones at Lysite Mountain and the muddy dolowackestones at Sheep Canyon, however, exhibit reservoir-quality porosity and permeability, similar to their subsurface equivalents, and show considerable laterally variability in those properties at the reservoir scale (Fig. 4). This scale of variability is significant in regard to reservoir performance (Jennings 2000; Pranter et al. 2005; this study) and would be difficult or impossible to determine from typical subsurface datasets. Information from outcrop analogues or horizontal wells is necessary to begin to quantify heterogeneity within dolomite rock fabrics or associated reservoir flow units.

For the Madison Formation at Sheep Canyon and Lysite Mountain, three components of lateral petrophysical heterogeneity are observed. These components included a near-random nugget effect, short-range variability and a longer-range periodic trend. The nugget effect for the dolowackestone and dolograinstone accounts for more than 50% of the overall variance in both porosity and permeability. The short-scale variability accounts for the balance, with a range of only 13–22 ft (4.0–6.7 m) for these rock fabrics. Yet the amplitude of the periodic trend has a variability that is as much as 17% relative to the total variance, which makes it a very important characteristic to include in a petrophysical model. Similar petrophysical heterogeneity has been documented in the Permian San Andres Formation of New Mexico (Jennings 2000; Jennings et al. 2000), suggesting these might be universal attributes of at least Palaeozoic shelfal dolostones. Further work is clearly needed on other reservoir analogues, particularly dolomites of younger ages, to establish the catalogue of petrophysical models that the reservoir analyst might choose as an appropriate analogue.

The simulation results of two-phase fluid flow through the dolograinstone and dolowackestone clearly illustrate the effect of petrophysical heterogeneity in dolostones. Small- and large-scale fingering, reservoir volume swept by the waterflood and breakthrough time are intimately related to rock fabric and the range (continuity) of the short-scale variability in each dolomite fabric. The extent of fingering increases, BTT decreases and sweep efficiency decreases with increasing range of short-scale heterogeneity. The degree of local (small-scale) fingering is due to the nugget effect and lower values for the range of short-scale heterogeneity. When there is large-scale fingering within a reservoir, the possibility exists to have larger areas of bypassed pay and lower recovery efficiencies. Therefore, the various scales of heterogeneity must be characterized because they affect the degree of fingering and this must be accounted for in reservoir development planning. In addition, dolostones with greater continuity of short-scale heterogeneity have shorter breakthrough times for injected fluids, which is critical...

![Fig. 13. Water saturation maps at 100 days for the eight heterogeneity models. Producer and injector wells are located at the lower left and upper right corners of each model, respectively. See Figure 12 for explanation of abbreviations.](image_url)

![Fig. 14. (a) Sweep efficiency (at 100 days) for the eight heterogeneity models and (b) water breakthrough times (BTT). See Figure 12 for explanation of abbreviations.](image_url)
information for production scheduling and the design of surface facilities.

Results also show that not all multiphase fluid-flow variables are sensitive to petrophysical heterogeneity in dolomites. The most sensitive are producer and injector bottom-hole pressures, which respond to differences in the rock fabric and degree of continuity in short-scale variability. This is important for wellbore design and stability. Because bottom-hole pressures are related strongly to reservoir heterogeneity, optimal well design should consider the effect of heterogeneity. Oil production rate, water injection rate, ratio of oil production and water injection rates, and watercut are sensitive, to a lesser degree, to differences in heterogeneity but are important parameters in the evaluation of the effectiveness of waterflooding. The most useful models of dolostone reservoir performance will be those that accommodate the type of lateral petrophysical heterogeneity revealed by outcrop analogues such as the Madison Formation. The potential limitations in using 2D versus 3D fluid-flow simulations are recognized; however, it is felt that these results show relative fluid-flow differences associated with the different scales of lateral variability.

Use of structured variogram models vs. experimental semivariogram

Traditional approaches of geostatistical modelling rely on using structured variogram models to generate the heterogeneity models of the petrophysics (Deutsch 2002; Kelkar & Perez 2002; Dubrule 2003). This introduces artificial dependence of the semivariogram model on the petrophysical models. In addition, very complex experimental semivariograms may not lend themselves to a well-fit semivariogram model. Due to these facts, structured variogram models do not always capture the true complexity of the petrophysical variance. In this study, this limitation is removed by using the experimental semivariograms directly instead of a semivariogram model. The use of actual covariance values (or covariance look-up tables) that are not generated by structured variogram models is not original to this study, having been used previously in fast-Fourier transform (FFT)-based modelling of covariance values by Yao & Journel (1998). What is important is that it is a more accurate approach than one that uses a semivariogram model derived from the observations. The fact that the sampling interval is 1 ft (0.3 m), allows for a well-defined, high-resolution experimental semivariogram. This enables direct use of the experimental semivariogram in petrophysical modelling and, it is believed, generation of a more realistic rendition of the true petrophysical variance. Use of structured variogram models vs. experimental semivariogram.

CONCLUSIONS

Porosity and permeability data from lateral transects through Mississippian dolomites of the Madison Formation, north and central Wyoming, exhibit three scales of lateral petrophysical variability. These include a near-random component, short-range variability and a long-range periodic trend. The sampled dolomites include a dolowackestone that represents outer and middle ramp mud-supported fabrics, and a dolograinstone that represents amalgamated skeletal and oolitic shales. The three scales of lateral petrophysical variability observed are similar in magnitude to those documented by other workers in Permain dolomites suggesting they are universal properties of ancient shelfal dolomites.

Fluid-flow simulation of heterogeneity models based on the outcrop data reveals the impact of near-random and short-scale petrophysical heterogeneity and rock fabric on reservoir performance. Fingering, sweep-efficiency, breakthrough time and bottom-hole well pressures are most sensitive to lateral reservoir heterogeneity and rock fabric. Dolomites with greater continuity of short-scale heterogeneity have higher degrees of large-scale fingering, higher sweep efficiency and shorter breakthrough times. For a given short-scale continuity, there is a higher degree of small- and large-scale fingering, lower sweep efficiency and longer breakthrough time for the dolowackestone versus dolograinstone models. Producer (and injector) bottom-hole pressures for the dolowackestone models are lower (and higher) than those for the dolograinstone models. These results underscore why it is important to quantify lateral petrophysical heterogeneity within dolomite reservoirs at the flow-unit or rock-fabric scale. Outcrop analogues of dolomite reservoir facies can provide the needed data.

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REFERENCES


