Advances in carbonate exploration and reservoir analysis

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Abstract: The development of innovative techniques and concepts, and the emergence of new plays in carbonate rocks are creating a resurgence of oil and gas discoveries worldwide. The maturity of a basin and the application of exploration concepts have a fundamental influence on exploration strategies. Exploration success often occurs in underexplored basins by applying existing established geological concepts. This approach is commonly undertaken when new basins ‘open up’ owing to previous political upheavals. The strategy of using new techniques in a proven mature area is particularly appropriate when dealing with unconventional resources (heavy oil, bitumen, stranded gas), while the application of new play concepts (such as lacustrine carbonates) to new areas (i.e. ultra-deep South Atlantic basins) epitomizes frontier exploration.

Many low-matrix-porosity hydrocarbon reservoirs are productive because permeability is controlled by fractures and faults. Understanding basic fracture properties is critical in reducing geological risk and therefore reducing well costs and increasing well recovery. The advent of resource plays in carbonate rocks, and the long-standing recognition of naturally fractured carbonate reservoirs means that new fracture and fault analysis and prediction techniques and concepts are essential.

A key area of progress has been integration of stratigraphic, structural, geomechanical and diagenetic analysis to populate reservoir models accurately. Dramatic increases in computing and digital imaging capabilities are being harnessed to improve spatial analysis and spatial statistics in reservoirs and ultimately improve 3D geocellular models.

It is commonly quoted that carbonate reservoirs contain some 50–60% of the world’s oil and gas reserves (e.g. Roehl & Choquette 1985). Indeed, the world’s largest oil field (Ghawar, Saudi Arabia) and the world’s largest gas field (North Field/South Pars straddling the Qatar/Iran border) are both reservoirs in carbonate rocks. The first discovery of hydrocarbons in carbonate reservoirs was in 1856 with the 1MMBO Heide field in Germany; however, it was not until 1884 that a major commercial discovery was made, namely the Lima–Indiana trend, in Ohio, USA (Keith & Wickstrom 1991). Interestingly, the Lima–Indiana trend was initially drilled for water, but deeper drilling (to 425 m), led to the discovery of a 500 MMBO oil and 2TCF gas field. This led to a drilling boom with some 100 000 wells being drilled in that trend alone – yet the placement of these wells was based on only a rudimentary understanding of the subsurface geology. Ironically, the Lima–Indiana wells actually penetrated a complex fault-related dolomite body (hydrothermal dolomite) – a play type that has seen a recent resurgence of activity both inside and outside of North America, such as the contribution of hydrothermal dolomites to the reservoir production in Ghawar field (Cantrell et al. 2001), and Khuff Formation reservoirs in the Middle East (Sudrie et al. 2006; Garland et al. 2008).

Since the late 1800s, our knowledge and understanding of carbonate reservoirs has of course improved beyond all recognition. This volume presents a snapshot of key recent advances in carbonate exploration and reservoir analysis, focusing on four main areas:

- emerging plays and techniques;
- improved reservoir characterization;
- impact of fractures and faults in carbonates;
- advances in geomodelling of carbonate reservoirs.

The papers were originally presented at a Geological Society London Conference, ‘Advances in
Carbonate Exploration and Reservoir Analysis’ in November 2010, where over 200 delegates attended a 2-day meeting. With 43 oral presentations and 28 poster presentations, topics ranged from emerging plays and concepts through to the impact of diagenesis and fracturing on carbonates, and geomodelling of carbonates.

Impact of research

The impact that academic research has had on improving our understanding of carbonate reservoirs should not be underestimated. Carbonate reservoirs are diverse and rarely simple, with diagenesis and fractures commonly playing a major role in modifying resulting pore systems and thus producibility. Burchette (2012) provides an excellent introduction to this by examining the pathways that carbonate research has taken in the past, and how research can mature in the future to mutually benefit academia and the industry. Since the 1950s, when research in carbonates started to have a direct impact on the petroleum industry (and vice versa), it has been clear that research topics have gone in and out of vogue. This has changed from understanding modern carbonate systems (1950s and 1960s) to using that knowledge to interpret ancient carbonate systems (1970s), the advent of seismic and sequence stratigraphy (1970s), and realizing the importance of diagenesis, stratigraphic forward modelling (1990s) and more lately reservoir modelling in carbonates (2000s). As Burchette (2012) comments, it would be unusual nowadays if reservoir description studies did not start by constructing a sequence stratigraphic framework. The advent of new technologies (3D seismic, and associated capability of mapping 3D geometries and attribute analysis) and computing capabilities (3D geocellular modelling) has undoubtedly influenced the direction in which research has been taken, generally with outstanding results (i.e. Eberli et al. 2004; Collon-Drouailliet et al. 2012; Fournillon et al. 2012; Janson & Madriz 2012; Lallier et al. 2012; Palermo et al. 2012).

So, which pathways should research take in the future? It would appear that research into the large-scale issues of reservoir architecture, facies belts, facies types and diagenetic processes have provided a large enough stock of analogues to enable comparisons to be made to most subsurface examples. Even so, new plays, although rare, are still being made today and require substantial research in order to catch up with our current knowledge – that is, lacustrine microbialites (see discussion below and Wright 2012). Collating and understanding quantitative data on the geometry and dimensions of carbonate depositional bodies is clearly an area that adds great value. Although there is a remarkable wealth of data in-house within companies and also in the literature on the size of depositional bodies, it is only recently that attempts have been made to collate these data into a useable format for geomodelling purposes. Major advances are being made towards better understanding carbonate diagenesis within stratigraphic and structural frameworks (see for example Dewit et al. 2012), and Burchette (2012) concludes that semi-quantitative digital forward modelling (reactive transfer modelling) can provide greater insight into the ways in which carbonate rocks transform during burial.

Burchette (2012) also notes that, in as much as super-giant fields (defined as five billion barrels or more recoverable oil) are in decline, there is undoubtedly a need to better understand more of the ‘producibility’ issues surrounding carbonates, such as pore and rock typing, permeability prediction, impact of fractures and diagenesis on carbonate productivity and impact of wettability, to name but a few. Fractures and diagenesis are particularly important in many tight oil and tight gas carbonate plays, and as these resource plays become more widespread, these issues and the related challenges of geomechanics and mechanical stratigraphy will become increasingly important.

Emerging plays and techniques

With over 100 years of research since the first carbonate petroleum discovery was made, it seems remarkable that new plays are still there to be discovered. Frontier exploration can be characterized as a function of the maturity of the area and the techniques used (Fig. 1). For example, in many areas where carbonate plays are well established, companies continue to explore in those areas using the same techniques and geological/geophysical concepts as for previous discoveries. Depending on the maturity of the area, this approach normally leads to more discoveries, but typically those discoveries are not giants, and simply add incremental reserves to existing plays. This approach builds on existing knowledge, applying it to an established area (old area, old techniques; Fig. 1).

Existing play concepts can also be applied to new areas, for example taking an established play from an onshore basin to the deep offshore area, or taking established plays to areas that have only recently ‘opened up’ owing to previous political upheavals (new area, old techniques; Fig. 1). This approach can commonly lead to new ‘giant’ discoveries, such as recent finds in Kurdistan, Iraq, that is, Shaikan (up to 10.8 bbo in place; Gulf Keystone 2011) and Miran West fields (up to 12 tcf gas in place; Heritage Oil plc 2011). Improved technology in existing plays has proved extremely important.
recently, with the advent of developing and producing heavy oil and unconventional hydrocarbons. This can be characterized as old area, new technique (Fig. 1). Applying new techniques and concepts to new areas (new area, new technique; Fig. 1) is always an exciting prospect for geoscientists, and this epitomizes frontier exploration. Typically this is a high-risk strategy, but it can be extremely rewarding.

Two papers in this volume discuss how emerging plays and techniques have advanced our understanding of carbonate geology. The Grosmont Formation (Machel et al. 2012) is an example of applying new techniques in existing areas, in as much as the resources are unconventional hydrocarbons (heavy oil/bitumen). The heavy oil/bitumen resources in the Grosmont Platform were discovered in the 1970s, but were deemed uneconomic because the technology was not available to exploit them. The reservoir is shallow (250–450 m), and is considered to contain 400–500 billion barrels of heavy oil/bitumen in place – currently the world’s largest unconventional oil reservoir hosted in carbonate rocks. Since its discovery, various attempts have been made to turn the resource into reserves, by using different production technologies (initially ‘huff and puff’ techniques). However, it was not until the mid 2000s that technology advanced sufficiently to exploit these resources, with the advent of thermal recovery methods such as steam-assisted gravity drainage and in-situ retorting. Now that the technologies have improved, there is a clear need to fully evaluate the reservoir in order to pinpoint the sweet spots for production. Machel et al. (2012) present the latest evaluation of the Grosmont reservoir geology, focusing on where and why reservoir sweet spots develop. The authors show how the Grosmont reservoir is a complex stacked carbonate succession that has undergone a long geo-history of dolomitization, fracturing, karstification and biodegradation. The fracture network is a result of at least three phases of tectonism and/or subsurface
diagenetic phases, Machel

ever, by understanding the timing and impact of the well tests) are complex and difficult to map. However, by understanding the timing and impact of the diagenetic phases, Machel et al. (2012) have shown that areas with bitumen having *in-situ* viscosities greater than 1 million cP and API gravities of 5–9° can be highly productive, forming sweet spots. The recognition of these sweet spots is critical for the successful exploitation of this resource.

True frontier exploration occurs where new geological concepts are applied to new areas. The recent pre-salt discoveries in the South Atlantic basin are remarkable examples of where new concepts (e.g., lacustrine carbonate plays) have been taken to new areas (e.g., pre-salt stratigraphy) using advanced drilling techniques (e.g., ultra-deep wells), resulting in super-giant discoveries (e.g., Lula and Cernambi fields, 6.5 and 1.8 BBOE respectively; reserves quoted from Offshore Magazine 2012). In this volume Wright explores the widely varying facies models for lacustrine deposits in rift settings and the subsequent reservoir architectures, composition and diagenesis. Microbialites are a common component of lacustrine settings, both in modern and ancient settings. Wright (2012) recognizes that microbial builds form in three main settings: (1) shallow lakes, spreading over extensive areas, such as Great Salt Lake in Utah; (2) deeper lakes, in discrete bathymetrically controlled facies belts such as Lake Tanganyika; and (3) associated with springs. When associated with springs, Wright (2012) notes that it is important to recognize the mechanism triggering carbonate precipitation: in shallow lakes, carbonate spring precipitation can be triggered by degassing, whereas in deep stratified lakes, Ca-enriched springwaters are responsible for carbonate precipitation (i.e., Pyramid Lake, Nevada, USA). Clearly the different mechanisms responsible for creation of microbial builds will result in spatial variability within facies belts, different geobody sizes, differing mineralogy and differing diagenesis. Wright (2012) also recognizes the importance of the origins of travertine in lacustrine settings, in as much as this has implications for reservoir size. Subaqueous spring-fed travertines need to be distinguished from subaerial travertines, because subaqueous travertines are typically small in size and thickness compared with their subaerial counterparts. Subaerial travertines have the capability to create topographic mounds and ridges; however, subaqueous springwaters typically admix with lake waters, and do not display the classical topographic features. The significance of a volcanic and thermal influence on lacustrine facies is also documented by Wright (2012), as is the potential for porosity development. Mg silicates can be a product of lakes fed by rivers draining volcanic terrains. The resultant chemistry of pore fluids can produce dolomite and silica, with porosity developed as a consequence.

Chasing new plays in new areas is always a challenge, because a basic understanding of the reservoir is essential even in the early stages of exploration. There is no doubt that these intriguing lacustrine carbonates will continue to be evaluated in the future, improving our knowledge of the special conditions, facies, chemistry, diagenesis and pore types experienced in these settings.

**Reservoir characterization**

The integration of multiple data sets is required to fully characterize a reservoir, in order to identify all of the properties that control the storage and production of hydrocarbons in that reservoir (Slatt 2006). Early work on understanding reservoirs to increase production was originally left to the engineers. However, over time it became apparent that integrating the geology into the reservoir model was a crucial phase of the reservoir characterization process (Slatt 2006). Carbonate reservoirs present a particularly challenging set of issues because of their high degree of geological and petrophysical heterogeneity (Lucia *et al.* 2003). The description of carbonate reservoirs needs to include (1) a thorough understanding of the spatial variation in lithofacies (which controls the degree of compartmentalization of the reservoir), (2) diagenesis of the carbonate unit (to understand the development of porosity and permeability), and (3) the mechanical stratigraphy and structural history of the basin (to understand the localization, attributes and timing of faults and fractures). This information is then integrated with petrophysical and seismic data to further refine reservoir heterogeneity.

Reservoir characterization begins with the development of a geological model, but it does not end there. The geological model, along with measured petrophysical properties such as porosity and permeability, is input into reservoir modelling software in order to obtain a two- or three-dimensional model with the best fit to data. This model can then be used for reservoir performance simulation and well planning (Slatt 2006). The topic of geomodelling is discussed in more detail further on in this
introduction and in several contributions to this volume, but it is important to note here that there is a strong tie between the quality of the geological characterization that goes into the model and quality of the modelling results. Much of the information available for reservoir characterization is by necessity from the subsurface, with the inherent problem of understanding geological variation between wells (Palermo et al. 2012, and references therein). The integration of subsurface data with outcrop studies therefore provides a vital link between small-scale variability that can impact reservoir performance, and larger-scale subsurface datasets (Palermo et al. 2012).

Three papers are included in the Reservoir Characterization section of this volume; each one deals with detailed geological interpretations of multiple data sets, and develops analogue examples that lead to improved reservoir characterization in carbonate reservoirs around the world. The first contribution, by Dewit et al. (2012), focuses on understanding the formation and distribution of hydrothermal dolomite (HTD) bodies. Of late, greater interest has been given to HTD bodies because they typically have increased porosity and permeability, and can therefore serve as reservoirs or as ‘sweet spots’ within a larger reservoir. The study by Dewit et al. (2012) bears on the overall geometry, and distribution of porosity and permeability within HTD bodies in the Ramales Platform in northern Spain. They interpret the location and geometry of the studied HTD bodies to be largely controlled by faults and joints that acted as permeable pathways for dolomitizing hydrothermal fluids. Three types of HTD are described, and the distribution of these types is shown to be controlled by the orientation of faults and joints, and by the strike of the platform edge. Two phases of dolomitization are responsible for the three types of HTD, with the earlier phase dolomites having higher porosity, but not permeability, than the later phase dolomite. This study has broad implications for understanding controls on the formation of hydrothermal dolomite, which then provide a basis for improving geological models for hydrothermal dolomite reservoirs in other basins around the world.

The study by Al-Qayim & Othman (2012) integrates geological and petrophysical characteristics of an Eocene reservoir in the Taq Taq field of northeastern Iraq. Using core, cuttings, outcrop and well log data, Al-Qayim & Othman (2012) describe two major microfacies within four previously defined lithofacies of the Pila Spi Formation. These microfacies represent varying degrees of dolomitization that led to increased porosity, particularly in two of the lithofacies. Using the microfacies descriptions, in conjunction with well log data and reasonable porosity cut-off values, six porosity units were recognized, and defined by their average porosity and permeability. The distribution of porosity and permeability within this carbonate is heterogeneous, and the recognition of these porosity units significantly aids in the identification of the microfacies with the best reservoir properties. Flow types were also determined using measured porosity and permeability from one well, calculated values from log data for the other three wells, and pore-throat classification within the microfacies. The flow type in the Pila Spi Formation varied from matrix flow to a fracture system superimposed on matrix flow, indicating that fracturing played a role in increasing reservoir quality. The integration of outcrop descriptions with petrophysical analysis and well log data results in a more detailed understanding of which stratigraphic intervals have the best reservoir properties. This type of information provides crucial input for a successful reservoir model.

The third contribution to reservoir characterization is the first part of an integrated study of the Triassic Upper Muschelkalk Group by Palermo et al. (2012). This paper documents lateral and vertical trends in reservoir properties from outcrop samples of a carbonate deposited along a gently dipping ramp that can be used as an analogue for other epeiric carbonate systems, as well as delving into the world of three-dimensional petrophysical modelling. The reservoir modelling results of Palermo et al. (2012) are discussed later in this paper in the section on Geomodelling.

Palermo et al. (2012) used extensive outcrop and quarry exposures to study lateral and vertical variability within the Upper Muschelkalk, through petrographic and petrophysical analysis. The authors recognize that high energy shoal and shoal-fringe facies develop the best reservoir properties because the lower mud content means that the flow of early diagenetic fluids that create mouldic porosity is not restricted. Lateral facies and diagenetic trends, and hence porosity and permeability trends, are continuous on the scale of kilometres, with gradual transitions to muddier and therefore less porous and permeable strata. In contrast, vertical changes in facies, diagenesis and the associated reservoir properties occurred on a decimetre scale, and are related to transgressive–regressive cycles that played a role in controlling the amount of mud available in the system, and also in the increase in early diagenesis associated with maximum regression. Palermo et al. (2012) give several criteria to aid in the prediction of reservoir properties in other epeiric carbonate reservoirs, including (1) understanding the facies associations and associated mud content; (2) recognizing the various scales of stratigraphic cycles that can impact mud content and early diagenesis during maximum regression; and (3) subtle palaeo-relief that may result in changes in facies

types, particularly porous facies on palaeohighs. These criteria can be applied to similar carbonate reservoirs in basins around the world, and as such this contribution provides valuable insight into controls on the lateral and vertical distribution of porosity and permeability trends in epeiric carbonate reservoirs.

**Fractures and faults**

Many low-matrix-porosity hydrocarbon reservoirs are productive because permeability is controlled by fractures and faults. Understanding basic fracture properties is critical in reducing geological risk and therefore reducing well costs and increasing well recovery. In carbonate reservoirs, opening-mode fractures (extension fractures, veins and joints) and faults commonly strongly influence production (Nelson 1985), but fractures present enormous characterization challenges because individually they may be quite small and hard to sample or detect despite advances in core analysis, well log and geophysical techniques (Hennings 2009). In many cases small fractures localized in clusters govern the hydraulic behaviour of faults (Ozkaya & Minton 2007; Questiaux et al. 2009). Also problematic is obtaining unique and testable predictions about fracture and fault attributes, in part because substantial fracture growth can be generated by minute extensional strains (on the order of $10^{-4}$; Olson et al. 2009) under a wide range of tectonic, burial and uplift histories (Engelder 1985). Consequently, fracture arrays form even in the absence of larger scale structures. Yet the effective permeability calculated for these low-strain fracture patterns can be considerable (Philip et al. 2005). Moreover, studies that include production data show that the challenge in many fields is not simply to intersect fractures, which may be widespread, but to intersect productive fractures (Rawnsley et al. 2007). A deeper understanding of how fractures form and what makes fractures good or poor flow conduits is therefore needed to advance carbonate reservoir analysis.

The preservation of open fractures (Fig. 2) depends on fracture size, fracture diagenesis (cementation and dissolution) and in-situ loading conditions. The fluid-flow paths through fractures are

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**Fig. 2.** Open fracture in Cretaceous Austin Chalk, core from Giddings field, Texas, USA. The vertical, open fracture in chalk terminates top and bottom at marl interbeds. Although the fracture is nearly completely open, it is locally bridged by calcite crystals (labelled ‘B’). This illustrates a ‘fracture stratigraphy’ controlled by the differences in mechanical properties of chalk and marl and also the role of natural cements in modifying fracture pore space.
difficult to predict because fractures typically vary significantly in size (Ortega et al. 2006), are heterogeneously developed in different sedimentary layers (Laubach et al. 2009) and may vary laterally over short distances (Pollard & Aydin 1988). Where fractures form and grow in a chemically reactive environment, such as the deeper parts of sedimentary basins (temperatures greater than about 50 °C) or in highly reactive material such as carbonate rock (Morse et al. 2007), mechanical properties evolve and both the fractures and their host rocks are susceptible to both dissolution and to cementation and porosity loss. Recent evidence that some fractures in dolostones may grow slowly over millions of years (e.g. Gale et al. 2010) emphasizes the likelihood that meaningful chemical and mechanical interactions are widespread. The papers in this volume that discuss fractures and faults by Jacquemyn et al. (2012), Fournillon et al. (2012), Iriarte et al. (2012), Machel et al. (2012) and Hooker et al. (2012) share the perspective that understanding concurrent structural and diagenetic processes is useful for understanding how fractures evolve as fluid flow conduits.

The influence of mechanically stratified carbonate rock sequences on the arrangement and types of fractures is a key to accurate fracture prediction in the all-too-common case where direct fracture observations are inadequate (Shackleton et al. 2005; Laubach et al. 2009, 2010). Jacquemyn et al. (2012) explore the interrelations of mechanical stratigraphy, fractures and dissolution, aiming to define the dominant factors that govern various karst types in outcrops that contain features typical of reservoirs with solution-enhanced fractures. In the Apulia Platform, dissolution features (karst) are mainly vertically oriented and appear to be related to pre-existing fractures. This is an example of dissolution of carbonate material and secondary porosity concentrated along fractures (Ferrill et al. 2004; Fournillon et al. 2012). Here and elsewhere, fracturing and karst dissolution reinforce one another by enhancing permeability (Jacquemyn et al. 2012). In the Apulia Platform, the Lidar scanning and fracture mapping show that common karst types are fracture enlargement and karst cavities in an inverse drop-like shape that ends in a fracture. Sedimentological cycles govern susceptibility to both fracture and dissolution (not necessarily the same) and mechanical layer thickness, resulting in a hierarchy of dissolution features. High fracture abundance (close fracture spacing) does not always correspond to extensive dissolution porosity. Because multiple fractures sets are present, the patterns are complex and not readily unravelled from stratigraphic evidence alone.

Dolomite occurs in many diagenetic environments, ranging from the surface to subsurface settings of several kilometres burial depth. Relict sedimentary textures show that many originate from the transformation of limestones, but the processes have long been contentious, and hydrothermal dolomite models are no exception (Machel & Lonnee 2003). Hydrothermal dolomites constitute major productive reservoirs (Cantrell et al. 2001; Lonnee & Machel 2006; Smith 2006), but much remains to be learned about these complex reservoirs from their outcrop analogues (Davies & Smith 2006; Iriarte et al. 2012). Although understanding the three-dimensional structure geometry and sizes of these bodies is essential, such studies rarely document the interaction of fluids and structures during deformation. The hydrothermal dolomite bodies outcropping in the Asón Valley (Basque-Cantabrian Basin, north Spain) are outstanding examples of this type of structural-diagenetic feature. Iriarte et al. (2012) describe evidence of hydrothermal fluid flow in fractures, synchronous structural features, fluid flow channelling and dolomitization processes that indicate a tectonic control. As fluid circulated, it concentrated preferentially in more fractured areas with increased permeability, and in extensional chimneys, thus creating dolomite bodies. Repeated extensive tectonic activity enhanced fracture porosity, transiently promoting overpressured fluid migration and cyclical dolomitization. These spectacular Asón Valley outcrops illustrate the role of deformation and fluid flow controlled by faults and fractures, the influence of these structures on the migration and channelling of dolomitizing fluids, and the role of cement as a repeatedly broken sealing material in the system (Iriarte et al. 2011). These outcrops also show how physically well interconnected fractures and faults readily become disconnected for fluid flow owing to cement deposits.

Within fracture networks, fluids flow through individual fractures that vary in size from the largest faults down to microfractures (Ortega et al. 2006). Consequently, a broad range of fracture sizes can play an important role in fluid flow. Many fracture systems in the deeper parts of sedimentary basins also contain, and locally are sealed by, natural mineral cements (Fig. 3; Nelson 1985; Laubach 2003), although this aspect of fracture arrays has been mostly overlooked until recently. The goal of the study by Hooker et al. (2012) is to explain how contrasting fracture size distributions arise in the context of cement precipitation. To explain the geological controls on size distribution, previous studies focused on the influence of rock mechanical properties and fracture propagation, but in this study textural evidence in cement that precipitated within fractures during opening is used to extract fracture growth histories. These cement deposits can be isolated within otherwise open fractures (Gale et al. 2010). Fractures having
power-law opening displacement patterns have fracture cement textures showing that these fractures opened incrementally, in tens to hundreds of tiny but similar-sized steps, whereas fractures in arrays with more uniform size distributions had different opening patterns. Simulating the process with a numerical model suggests that patterns of fracture-cement deposition during opening influence the tendency for deformation localization in fractures. The observations and model in Hooker et al. (2012) apply to fracture widening, but can be applied to length and height growth.

These three papers are related to developments in well testing in fractured reservoirs described elsewhere (Corbett et al. 2012). In fractured reservoirs fluid flow occurs in high-permeability and low-porosity fracture systems that surround, and may permeate, matrix blocks over a wide range of scales. Even isolated fractures may have a profound effect on permeability in carbonate rocks, if flow through the rock mass between fractures is possible (Philip et al. 2005). Simulation of such reservoirs is challenging in terms of both characterization and numerical modelling. Using links between depositional

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Fig. 3. Palinspastic reconstruction illustrating the progressive stages of opening of a calcite-filled fracture. Reconstructions such as this are used by Hooker et al. (2012) to document how fractures grow through time. Growth histories are used to guide models that predict fracture-size distributions. Hooker et al. suggest that such cements are not mere passive markers of fracture growth, but may themselves affect how fractures grow.
and mechanical stratigraphy, between mechanical stratigraphy and fracture abundance, size and clustering patterns, and between fractures and diagenesis can help improve simulations.

**Geomodelling**

Over the past decade, there has been an exponential increase in our computing and digital imaging capabilities. It is therefore not surprising that these tools are being harnessed to improve our understanding of spatial analysis and spatial statistics and their input into 3D geocellular models. This allows us to understand reservoirs better and to improve their subsequent production and recovery factors, a significant move forward indeed. It is also of relevance in hydrogeology with regard to modelling aquifers, which will become increasingly important in the coming years. Many well-proven programmes are available at a cost affordable by industry, but there has also been increasing use of free software available on the internet (Myers 2006). It is important to recognize that data processed by different packages may not produce the same results (Myers 2006).

Some of the background to geostatistics that are then used in geomodelling is given in Coburn *et al.* (2006) and Myers (2006). Two types of model exist – deterministic (predictable behaviour) and stochastic (incorporates a degree of randomness). Karlin & Taylor (1998) suggested that a deterministic model would predict a single outcome for a given set of circumstances, whereas a stochastic model could predict a set of possible outcomes weighted by probability and possibly of more use when trying to model geological bodies. Myers (2006), however, suggests that the distinction can be blurred.

The term ‘geomodelling’ captures a plethora of geostatistical ideas and studies, as is clearly demonstrated by the papers in this volume (Collon-Drouailllet *et al.* 2012; Fournillon *et al.* 2012; Janson & Madriz 2012; Jung *et al.* 2012; Lallier *et al.* 2012; Palermo *et al.* 2012 ). These studies range from specific measures such as Hornton parameters and the application of Lidar through two-point statistics (e.g. variograms, kriging and sequential Gaussian simulation) to multipoint statistics. Geostatistics therefore covers a range of techniques that can be used to map geological surfaces and the variability between those surfaces from limited data and to predict the characteristics and values at locations for which there are no samples.

A difficulty for geologists working with geostatistics is that it requires a set of skills that, up until now, has not normally been incorporated into their training. Myers (2006) suggested that ‘the most devoted of geostatisticians contend that traditional statistical methods are totally ineffectual at incorporating spatial variability’. Spatial variation is key to our science, and in an attempt to be more predictive, techniques such as variograms and kriging, multipoint analysis and Bayesian statistics are now commonly being used but are perhaps poorly understood by many.

**Variograms, kriging and sequential Gaussian simulation**

Variograms (e.g. Gringarten & Deutsch (2001), which form the basis of traditional two-point statistics, are one of the key inputs to a geostatistical model in that they quantify the spatial variability of the geological parameter being studied (e.g. porosity or permeability) and are required before numeric geological models can be generated.

Kriging (named after D. J. Krige; Matheron 1963) is a means of averaging data that calculates the weighted mean and standard deviation at each point (Palermo *et al.* 2012). It uses the variogram and a spatial preference to calculate a weighted average for adjacent samples to estimate an unknown value at a given location (Gringarten & Deutsch 2001) and therefore takes into account both distance and direction. The ‘moving average’ differs, in that it is based on the average value of the data and only weights the distribution according to the distance from data points, and so has no spatial preference (Chou 1975, Palermo *et al.* 2012).

Sequential Gaussian simulation, represents the variable as a random deviation from the Gaussian (normal) distribution and therefore represents the input data and trends better than most kriging algorithms (Palermo *et al.* 2012).

**Multipoint/multivariate statistics**

Multipoint and multivariate statistics is a field that is becoming increasingly popular with geomodelers, not only to recreate the geometry and internal architecture of geological bodies, but also to numerically model fluid flow through a quantitative description of reservoir porosity and permeability. In the last decade, it has been shown that multipoint statistics (where statistical analysis ties several points together rather than just two, as for traditional variograms) can more accurately represent reservoir heterogeneity with variable characteristics (multivariate). Various authors (e.g. Guardano & Srivastava 1993; Krishman & Journel 2003) have proposed that multipoint statistics could characterize the random function inherent in many geological bodies to a greater degree than conventional two-point statistics.

Pixel-based (or point-to-point) simulations are based on variograms whereas object-based simulations
are based on the occurrence of geobodies and their properties at random points. Multipoint simulations combine these two processes. They are run using pixel-based methods but with a set of conditional probabilities for each pixel value. For this, a training image is required that is based on reality showing the geometry and distribution of objects (Gebbers & de Bruin 2010). Developing a training image requires good outcrop analogues for subsurface sequences, and this often causes problems with current research using multipoint statistics. Several of the papers in this volume have employed such methods (e.g. Fournillon et al. 2012; Janson & Madriz 2012; Jung et al. 2012).

Using Lidar and multipoint statistics, Janson & Madriz (2012) were able to recreate both the geometry and internal architecture of outcropping carbonate mounds, but the models required complicated training images and complex multigrid simulation that might be hard to implement in the subsurface. Current research, however, is focused on this, and over the next few years significant developments are likely to occur.

Jung et al. (2012) have overcome some of the problems with training images by using the database of geobody information termed ‘Carbdb’. This has enabled the development of a hierarchical methodology to further the deterministic model of grainstone shoals in the Muschelkalk of SW Germany (Palermo et al. 2010).

Another multipoint statistical technique discussed in this volume (Fournillon et al. 2012) is principal component analysis. Many datasets today have far more measurements made than actual samples (this is particularly true in the life sciences, e.g. Ringnér 2008) but is also true in the geological sciences when trying to fully characterize the variability of a natural phenomenon such as karst (e.g. Fournillon et al. 2012). The dimensionality of the data is therefore significant and principal component analysis is an algorithm that can reduce it while retaining most of the variation of the dataset. Certain characteristics show maximum variation, and Fournillon et al. (2012), have identified 11 of these in their karstified terrain as their principle components. These have then been plotted in such a way as to show the similarities and differences in a visual way.

Applications of geomodelling

Palermo et al. (2012) presents the second part of an integrated study investigating the development and distribution of Triassic even-bedded carbonates in the South German Basin. These were deposited on a gently inclined carbonate ramp, and can be observed in a series of excellent quarries and outcrops. The spatial distribution of lithofacies (Palermo et al. 2010) and reservoir properties (Palermo et al. 2012) was investigated at different scales (<1 m to kilometres). Using outcrop analogues and geomodelling techniques, the variability within the sequences was shown to be much greater on a vertical scale than horizontal, mainly controlled by stratigraphic cycles. This paper and that of Janson & Madriz (2012) add to the relatively scarce quantitative dataset on carbonate rock bodies.

Palermo et al. (2010) developed a detailed deterministic geological model for the sedimentology that has been used as the basis for this geostatistical study investigating the variability of porosity and permeability at different scales. Initially, the facies had to be modelled with sufficient spacing of data points to represent the complex facies geometries as a continuous property (Palermo et al. 2010). Significant care had to be taken to produce a model with a good match to the data.

In the reservoir study (Palermo et al. 2012), a variogram analysis was carried out on the dataset at spacings of 10 m to a few kilometres, but reasonable results could only be achieved by using large bin sizes and ranges similar to the observed facies changes. All the shoal facies associations (fringe, mid and inner) showed a nugget effect (high random values). A reasonable variogram model could only be made for the largest scale (kilometres). The intermediate scale (tens of metres) and the centimetre scale did not provide enough data to make a sufficient variogram analysis.

Jung et al. (2012) follow on from the work of Palermo et al. (2010) on carbonate shoal bodies in the Muschelkalk of SW Germany (also see Palermo et al. 2012) and present a workflow for the 3D modelling of carbonate reservoirs using multiple-point statistics (MPS). The methodology involved (1) setting up a hierarchical classification scheme for the carbonate geobodies encountered using analogues from ‘Carbdb’ (Jung et al. 2010; Jung & Aigner 2012), and (2) the subsequent construction of training images based on these data to build a 3D reservoir model with MPS. Training images require information such as the dimensions, geometries and distribution patterns of facies to build conceptual depositional patterns. Carbdb has been designed to organize and store such information so that it can be used in MPS.

As already discussed, many geostatistical studies use variograms to construct stochastic simulations. Jung et al. (2012) suggest that there are limitations to this process when modelling the complex depositional patterns that are commonly encountered in carbonate environments. They suggest that MPS allows for the generation of these complex shapes, and is easy to condition when there are abundant well data. With the methodology they suggest, it is possible to import realistic depositional patterns.
into the stochastic simulations, such as those from recent subtidal environments in Abu Dhabi, via training images. As a test, the results have been compared with the previous deterministic model of grainstone shoals in the Muschelkalk of Palermo et al. (2010). The MPS simulations have been found to produce geologically more realistic distributions and heterogeneity similar to those observed in modern carbonates. Simulating the depositional patterns using the stochastic technique of MPS has also been found to be much faster than deterministic modelling, for example via interactive facies mapping.

Janson & Madriz (2012) also note that most studies have been conducted on clastic systems (e.g. Deutsch & Wang 1996; Falivene et al. 2006), but that the database of studies is much more limited for carbonates. In this volume, the authors provide a comparison of a surface (thickness)-based approach with an MPS approach to describe and model a lower Carboniferous mixed carbonate/clastic sequence. This sequence comprises phylloid algal mounds at the shelf edge, which contain mound cores and associated debris in varying proportions dependent on their position on the shelf and original water depth. Detailed stratigraphic and facies data were collected and digitized along with Lidar data followed by various geostatistical simulations. Two models were generated using different approaches, and although both were successful, they highlight the difficulties of using geomodelling techniques in the subsurface.

The first was a surface-based model where the base and top of the mounds were mapped along their exposure faces. Using two-point geostatistics and sequential Gaussian simulation (normal distributions), the three-dimensional thickness of the mound was calculated (e.g. Journel 1983; Deutsch & Journel 1992; Goovaerts 1997). This was insufficient to describe the internal structure of the buildup, however, and strong trend data from vertical proportion curves of the different facies types (mound core and debris) were also required using more complicated Bayesian statistics. This would clearly work well where detailed outcrop data were available, but would be more difficult in the subsurface where data are scarce.

The second model was based on multipoint statistics with a pixel-based approach. With this, Janson & Madriz (2012) were able to recreate both the geometry and internal architecture of the mound, but it required a complicated training image and complex multigrid simulation. Again, they concluded that this would be hard to implement in subsurface.

The study clearly showed that modelling carbonate sequences, their geometry and internal architecture is not easy, in that both models had their strengths and weaknesses. Complex workflows are involved with both and in order for them to be successful they require significant amounts of prior knowledge. This can be extracted from detailed outcrop studies using detailed sedimentary logging and Lidar techniques, but clearly would be much more difficult to achieve in the subsurface where reliable geological data are scarce.

Two papers on the modelling of branchwork karst terrains have been included in this volume, by Fournillon et al. (2012) and Collon-Drouaillet et al. (2012). Karst is important not only for the hydrocarbon industry, but also for the water resources industry. The inherent heterogeneity and complexity of these terrains make them ideal cases to attempt modelling using geostatistical methods.

Fournillon et al. (2012) have stochastically simulated outcrop and subsurface Jurassic karstified sequences. By using geometrical and topological parameters derived from 2D karst maps, they have been able to model a well-constrained cave system in the Vars area of SE France using a pixel and variogram-based stochastic simulation method. Principal component analysis of the 11 factors that were recognized to characterize the caves was used to identify the main characteristics of the karst system. This was then compared with a structure-based modelling approach to simulate an unexplored karst system within the faulted and folded Môrîères Massif.

In the Vars area, three types of caves were identified using a multipoint approach – large and simple caves with long branches, smaller and more complex caves, and a group of small but simple caves. None showed any specific geographical distribution. Three groups were also observed in the Môrîères Massif with both similarities and differences to the outcrop cave data. To explain the differences between the datasets, additional factors and training images need to be added to the multipoint analysis in the manner suggested by Janson & Madriz (2012).

Like Fournillon et al. (2012), Collon-Drouaillet et al. (2012) have tried to simulate karstic networks using geostatistics. Again, their method is to compute a karst skeleton and stochastically determine the karst envelope around it. One of the key controls is the degree of branching of the cave systems. The Horton–Strahler number is a measure of the number (or order) of branches where each branch is an offshoot of a previous one. The branching complexity of a network can be described by the Horton bifurcation ratio, based on the law of stream numbers (Horton 1945). This method, originally developed for fluvial systems, has yet to be proved reliable in karstic systems, as they are not organized along a single horizon but are commonly in several layers with multiple interconnections (e.g. along repeated bedding planes, palaeowater tables
and fractures). These features have been incorporated into the simulated karst network discussed in the paper.

As well as using Horton parameters, variograms, kriging and sequential Gaussian simulation techniques have been used by Collon-Drouaiillett et al. (2012) and involve the following steps:

1. Discretization of the geomodel using PipeNet-work into a set of pipes and nodes simulating connectivity;
2. Creation of a karst skeleton of preferential flow paths between inlets and outlets;

Lallier et al. (2012) consider the use of deterministic and stochastic methods to attempt to manage stratigraphic uncertainty in the subsurface within an isolated buildup in the Philippines (Malampaya buildup, Offshore Palawan). In the subsurface at the scale of a reservoir, there is generally a lack of seismic resolution, and identifying stratigraphic or reservoir layering can be problematic, owing to boreholes commonly being drilled in locations that may not always be representative of the unit as a whole.

As already shown by Fournier & Borgomano (2007), the petrophysical properties of the Malampaya buildup are controlled largely by diagenesis, and the reservoir has been subdivided into diagenetic units using well logs, cuttings, cores and thin sections. Units were correlated if they were the same diagenetic type and showed similar well log signatures. Lallier et al. (2012) recognize, however, that correlations can be difficult, especially when dealing with diagenetic lenses that may, or may not, be continuous from one well to the next. There are ways of dealing with issues such as diagenetic discontinuities (e.g. the ‘one to many correlation’ of Waterman & Raymond 1987), but the mathematical expression of this is not easy and such uncertainty affects both the geostatistical simulations and the dynamic reservoir model, as well as fluid-flow predictions. In this study by Lallier et al. (2012), the diagenetic units have been correlated through similarities between wireline responses and using lithostratigraphic rules, for example, assuming that the sedimentary record is complete and there has been no distortion of the wireline log response between wells.

Lallier et al. (2012) have generated four stratigraphic models, one deterministic and the others stochastic, incorporating geostatistical simulations of porosity, permeability and acoustic impedance that have been used to generate synthetic seismic and flow models. It was expected that a variogram model could discriminate between the different diagenetic units, but this was not the case, possibly because the data came from five wells only. A unique spherical variogram model was therefore generated, conditioned by the five wells, and used to simulate porosity and acoustic impedance for the synthetic seismic models using sequential Gaussian simulation. Permeability was modelled using the porosity–permeability crossplots presented by Fournier & Borgomano (2007).

The different stratigraphic correlation models that were generated and the associated oil saturation and drainage models varied significantly, and emphasize how these models can impact the decision-making process in reservoir development. Lallier et al. (2012) suggest that the approach they have taken could be used to generate a set of models representing reservoir stratigraphic uncertainties prior to the onset of development.

In terms of geostatistics, therefore, the papers in this volume are a good indication of the current state of the field. Well-proven techniques such as variograms, kriging and sequential Gaussian simulation are commonly used in geomodelling. Clearly there are advantages to using and trying to improve our methods in multipoint statistics, and over the next few years advances are likely to be made in that respect. At the moment, the difficulty appears to be the need for complex training images to validate the models generated requiring significant understanding and input.

Conclusions

Successful oil and gas exploration and development in carbonate rocks continues to build through the application of new techniques and concepts. Ultra-deep carbonate reservoir targets and diagenetically and geomechanically complex resource plays in carbonate rocks, and the long-standing challenges of karst and fractured carbonate reservoirs, emphasize the need for integrated stratigraphic, structural, geomechanical and diagenetic analysis to accurately populate increasingly sophisticated reservoir models.

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