Structurally complex reservoirs: an introduction

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Abstract: Structurally complex reservoirs form a distinct class of reservoir, in which fault arrays and fracture networks, in particular, exert an over-riding control on petroleum trapping and production behaviour. With modern exploration and production portfolios commonly held in geologically complex settings, there is an increasing technical challenge to find new prospects and to extract remaining hydrocarbons from these more structurally complex reservoirs. Improved analytical and modelling techniques will enhance our ability to locate connected hydrocarbon volumes and unswept sections of reservoir, and thus help optimize field development, production rates and ultimate recovery. This volume reviews our current understanding and ability to model the complex distribution and behaviour of fault and fracture networks, highlighting their fluid compartmentalizing effects and storage-transmissivity characteristics, and outlining approaches for predicting the dynamic fluid flow and geomechanical behaviour of structurally complex reservoirs. This introductory paper provides an overview of the research status on structurally complex reservoirs and aims to create a context for the collection of papers presented in this volume and, in doing so, an entry point for the reader into the subject. We have focused on the recent progress and outstanding issues in the areas of: (i) structural complexity and fault geometry; (ii) the detection and prediction of faults and fractures; (iii) the compartmentalizing effects of fault systems and complex siliciclastic reservoirs; and (iv) the critical controls that affect fractured reservoirs.

Structurally complex reservoirs form a distinct class of reservoir in which fault arrays and fracture networks, in particular, exert an over-riding control on petroleum trapping and production behaviour (Møller-Pedersen & Koestler 1997; Coward *et al.* 1998; Jones *et al.* 1998; McClay 2004; Swennen *et al.* 2004; Sorkhabi & Tsuji 2005; Lonergan *et al.* 2007), (e.g. Fig. 1). With 'easy oil' becoming scarce, modern exploration and production portfolios are commonly held within geologically complex settings, in which reservoirs of this type are the common form. This means that there is an increasing technical challenge to find new prospects and to extract remaining hydrocarbons from structurally complex reservoirs in mature provinces such as the North Sea. New technologies developed in recent years permit exploration in increasingly hostile environments and economic development and production from some structurally complex discoveries that were previously 'parked' decades ago for technology catch-up. Our understanding, detection and ability to model and predict the complex distribution of faults, fracture networks, and other reservoir heterogeneities and their fluid compartmentalizing effects and storage-transmissivity characteristics, is a critical element in predicting the dynamic fluid flow and geomechanical behaviour of these fields under production conditions. Improved analytical and modelling techniques enhance our ability to locate connected hydrocarbon volumes and unswept sections of reservoir, and ultimately help optimize field development, production rates and ultimate recovery.

Geoscientists and engineers are addressing these issues within research institutions and operating asset environments around the world. Although research initiatives on structurally complex reservoirs vary considerably in scope, size and content, their ultimate goal from a practical perspective is to optimize the production of hydrocarbons from reservoirs. The research programmes brokered by the Industry Technology Facilitator (ITF) in the UK are a good example of such initiatives. These were 3-year thematic research collaborations between nine oil companies and over 25 academic and related research institutions in Europe, the USA and Australasia. The research programmes were specifically designed to improve our understanding

From: JOLLEY, S. J., BARR, D., WALSH, J. J. & KNIPE, R. J. (eds) *Structurally Complex Reservoirs.* Geological Society, London, Special Publications, **292**, 1–24.
DOI: 10.1144/SP292.1 0305-8719/07/$15.00

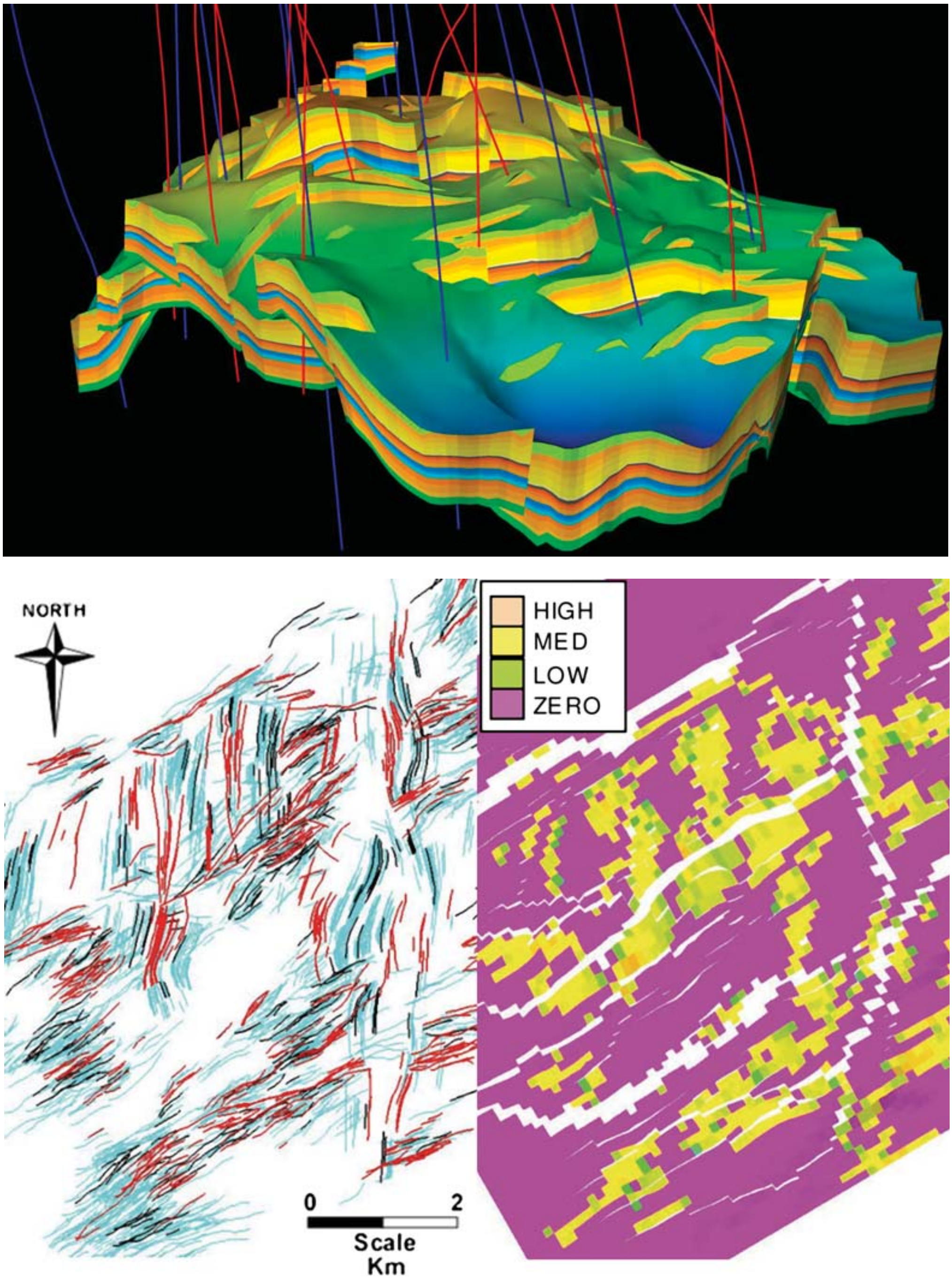

Fig. 1. Examples of structurally complex reservoirs. (**a**) Geo-cellular model of an intensely faulted field from the North Sea, in which shallow marine reservoirs are disaggregated into a patchwork of fault blocks. These fault blocks are mostly compartmentalized by sealing faults, and an intra-reservoir shale formation. Most of the fault blocks therefore require a dedicated producer well, and a water injector well to give pressure support to the producer as the block depletes. (**b**) Models of the fractured Clair reservoir, UKCS (fig. 12 of Barr *et al.* 2007). On the left are multiple stochastic realizations of a discrete fracture (conductive fault) network. One realization is shown in black and nine others generated using the same method, but with different seed numbers, in cyan. The red realization was made using a different method but with the same seed number as the black realization. On the right is a geo-cellular model showing upscaled effective fracture permeability from one realization.

of the broad range of geoscience and engineering issues associated with production from these complex reservoirs. The results were the catalyst for an international conference (held 28 February – 2 March 2006) and this Special Publication, which brings together a critical mass of papers on related topics. Together they provide the reader with an overview of global research on structurally complex reservoirs.

This introductory paper aims to provide context to this collected work (papers cited in bold are those presented in this book) and an entry point into the subject. We have selected a series of sub-themes for this overview, which include: (i) structural complexity and fault geometry; (ii) the detection and prediction of faults and fractures; (iii) the compartmentalizing effects of fault systems and complex siliciclastic reservoirs; and (iv) the critical controls that affect fractured reservoirs. A final section gives a brief comment on future directions and priority areas that emerge from the collected papers.

Structural complexity

The past couple of decades have seen the emergence of a variety of significant innovations in the analysis and modelling of structurally complex reservoirs. These developments have been driven mainly by the increased demands of the oil and gas industry and its reservoirs, but have also, crucially, been underpinned by vast improvements in both the quantity and quality of available data. 3D seismic datasets are now common and have been supplemented by a multitude of processing techniques and attribute analyses that facilitate the definition and mapping of structures. Just as 2D seismic has given way to 3D, recent developments in the technology of 4D seismic provide strong indicators that direct imaging of the impact of structures on flow will eventually become an essential tool in optimizing production from many complex reservoirs. Well production data have also increased in both quality and quantity, providing more refined indicators of reservoir production flow and pressure, with the improved constraints arising from horizontal wells and inclined well trajectories, and the general increase in the number of wells available from mature fields in particular. In addition, improved core recovery and improvements in the geological and fluid flow data from reservoirs have been matched by developments in both the capacity and functionality of existing modelling approaches. All these developments have enabled and stimulated both fundamental and applied research on the many technical issues related to the study of structurally complex reservoirs.

This volume presents a series of papers on the full range of these technical issues. The complete workflow of the reservoir structural geologist is well represented, with papers extending from the detection, mapping and prediction of faults through to fault property modelling and flow modelling of reservoir production. The running order of papers generally tracks this workflow, with the downstream side of it being essentially subdivided into faulted siliciclastic reservoirs and fractured reservoirs. This basic distinction is important, since it focuses the emphasis of studies which address the impacts of structural complexity on reservoir fluid flow.

In many siliciclastic reservoirs, the reservoir units which host the hydrocarbons have higher porosities and permeabilities than the faults that transect them. In these circumstances, the faults are detrimental to flow, acting as baffles or barriers within a generally more permeable host rock sedimentary sequence (e.g. Knipe 1993; Downey 1994; Knipe *et al.* 1997, Yielding *et al.* 1997; Jones *et al.* 1998; Manzocchi *et al.* 1999, 2002; Hesthammer & Fossen 2000; Fisher *et al.* 2001; Brown 2003; James *et al.* 2004). Issues such as the primary connectivity of reservoir units will also impact the behaviour of the flow system. In fractured reservoirs, the host rocks (which include limestone, chalks or granite/basement as well as siliciclastic rocks) generally have lower permeabilities than the faults and fractures that transect them (Reiss 1980; Plumb 1994; Nelson 2001; Lonergan *et al.* 2007). Fluid flow in such reservoirs incorporates the combined effects of pervasive fracture systems, including joints, combined with faults. In these circumstances, the faults will often represent the main flow pathways that tap into the host rock volume which provides the hydrocarbon storage capacity. In a low porosity rock such as granite, storage is primarily in the fracture system but the storage and flow domains may be separate (e.g. with most storage in joints but most flow in conductive faults). In an impermeable but porous rock like some chalks, storage is primarily in the matrix (host rock) but flow is in the fractures. Some siliciclastic fractured reservoirs have a similar split between the flow and storage domains, but in others the matrix permeability is high enough to provide a significant flow contribution, leading to particularly complex behaviour during hydrocarbon recovery. Some fractured limestone reservoirs similarly have zones of high matrix porosity, or of leaching (e.g. palaeokarsts) or secondary porosity (e.g. due to dolomitization).

This duality of faults and fractures as flow conduits or barriers is a fundamental property and provides the primary distinction between the two reservoir types. Faults within higher porosity-permeability reservoir units can represent baffles/barriers whereas faults in tighter porosity, lower permeability reservoir units, can act as conduits to fluid flow. This duality of behaviour is not drawn on geographical grounds, but can in fact occur on the same structure intersecting different rock sequences, or form on the same structure at different times, when the host rock properties and deformation conditions have changed over geological time. The convenience of defining end-member faulted reservoirs, nevertheless, provides a useful conceptual framework, even if individual reservoirs or faults may sometimes incorporate both types of flow behaviour. For example, faults within fractured reservoirs may act as both seals and conduits over different parts of the fault surface or even at different times during the production history of the field.

Fault geometry

Characterization and modelling of individual structurally complex reservoirs, typically begins with the 3D seismic definition and mapping of faults and other structures. Using newly developed modelling tools it is now possible to generate high quality 3D structural 'framework' models which can cope with structural complexities, such as intersecting and mutually cross-cutting faults, but also provide a means of examining displacement variations and cross-fault juxtapositions (Badley *et al.* 1990; Needham *et al.* 1996; Rutten & Verschuren 2003). These analyses are central elements in many of the studies presented in this volume and are now relatively routinely performed on reservoirs characterized by normal faulting. Geometrical complexities, including those involving cross-cutting and antithetic faults (and related branch-lines), and rapid changes in fault system polarity, present challenges to existing modelling techniques and have led developers to research alternatives which can better represent geological 'reality' (e.g. **Hoffman & Neave**). However, geological modelling is often conducted with the aim of producing geo-cellular models for use in reservoir flow simulation. Thus, it is necessary not just to honour relevant geological complexity at the 'input' stage of the 3D structural model, but also at the 'output' stage of the simulator grid. The adverse consequences of failing to do so are amply demonstrated in the field examples provided by **Fisher & Jolley**.

Tertois & Mallett show that newly developed methods of tetrahedral volume modelling are capable of modelling such complexly faulted reservoirs, and **Matthäi *et al*.** describe a hybrid meshing approach which, combined with innovative methods for the discretization of governing equations, could provide a comprehensive basis for future modelling efforts. Nevertheless, for the foreseeable future, most simulation of structurally complex reservoirs will take place in 'conventional' simulators operating on more-or-less regular grids of six-sided cuboid-shaped cells. More sophisticated approaches can and should be used to 'ground-truth' such simple models so that we understand the consequences of simplification and where it is or is not acceptable to do so.

A recurrent theme in the reservoir modelling of structurally complex reservoirs is that the technical limitations of reservoir modelling packages and the computing hardware which runs them will always be a constraining factor, and that their improvement will always lag behind our technical demands. Interpretation, mapping and visualization tools, by contrast, are now very refined, as are those permitting structural modelling of various types (e.g. displacement analysis, restoration, cross-fault juxtaposition analysis). These tools arise not only from the practical demands of reservoir studies but also from developments arising from research into the geometry and kinematics of faults. Indeed current models for many fundamental aspects of faulting either derive from, or were significantly advanced by, the analysis of seismic data at reservoir scales, including: (i) fault growth models (e.g. Walsh *et al.* 2002); (ii) polygonal faulting (e.g. Cartwright 1994; Watterson *et al.* 2000); (iii) salt-related deformation (e.g. Vendeville & Jackson 1992*a*, *b*; Jackson 1995); (iv) relays and segment linkage (e.g. Childs *et al.* 1995); and (v) fault populations (e.g. Yielding *et al.* 1996; Cowie *et al.* 1996). There are, of course, many outstanding technical issues relating to the geometry and kinematics of faults, some of which are considered in this volume.

Some reservoirs are characterized by very complex fault geometries with different modes of faulting developed at different times and with varying degrees of reactivation. These types of reservoir present a major challenge because although quantitative constraints on normal faults are relatively good, the characteristics of reverse fault systems and strike-slip fault systems, in particular, are less well understood and therefore much less predictable. Similarly, the nature and controls on the reactivation of earlier faults is not well understood, not just on geometrical grounds, but also in terms of flow. Nevertheless, **Domínguez** provides a comprehensive description of structural complexity arising from the interaction of two different fault trends and later fault reactivation in the Penguins field cluster, North Sea. Although this study shows how structurally complex reservoirs can arise from a relatively simple configuration of deformations, careful analysis is capable of unravelling the structural evolution of the fault arrays. **Barr** shows that contractional inversion of earlier rift-related normal faults in Southern North Sea gas fields has implications beyond the purely geometrical, with the breaching of earlier seals and creation of conductive fracture networks sometimes having a profound effect on reservoir flow.

Many of the studies in this volume have been conducted on reservoirs which include what might be considered relatively conventional tectonic normal fault systems and existing constraints on their geometry, at least in a generic sense, are generally good. High quality reservoir modelling demands the accurate characterization of fault geometries as a prelude to fault seal prediction (e.g. **Dee *et al*.**), juxtaposition analysis (e.g. **Myers *et al*.**) and fault property characterization and modelling (**Fisher & Jolley**; **Zijlstra *et al*.**), and therefore benefits from existing geometrical constraints. Similarly our current knowledge of the geometry and growth of gravity-slide normal fault systems, related either to the instability of delta slopes or salt, is now quite refined. The analysis and restoration of related structures of both tectonic and gravity-driven fault systems from 3D seismic data has provided excellent constraints on their kinematics (e.g. Jackson 1995). Physical modelling has made a significant contribution to our knowledge of fault array development (e.g. McClay *et al.* 2002) and the kinematics of gravity-driven fault systems, in particular (e.g. Vendeville & Jackson 1992*a*,*b*). The work of **Krézsek *et al*.** shows how recent technological innovations in imaging and quantifying deformation are capable of defining refined models for the kinematic evolution of margins characterized by salt-related thin-skinned tectonics. We anticipate that similar types of physical modelling studies will provide excellent constraints on the origin, geometry and growth of these types of fault system. Footwall collapse-related landslides are a type of gravity slide system which is less well understood, despite the fact that it is now well established that they dominate the structure of many reservoirs, including some in the North Sea. Although these reservoirs present challenges that are very different from other types of faulted reservoirs, they have not received a great deal of attention. **Welbon *et al*.** provide a comprehensive consideration of landslide structures and outline the challenges and opportunities provided by reservoirs in landslides and a new workflow for their characterization.

The foregoing discussion highlights some of the technical issues associated with fault systems that have different geometries, origins and multiple event histories. These issues are generally the subjects of the first phase of reservoir characterization, which is mainly conducted by seismic interpretation, sometimes supplemented by core analysis. The results of this type of analysis provide the essential backdrop for later phases of the structural geology and flow modelling workflow. This workflow involves a variety of technical components, the selection of which depends on the characteristics and type of reservoir concerned.

Detection and prediction of faults and fractures

Fault detection

Fault and fracture prediction in the modern exploration and production industry typically begins with 2D or 3D seismic interpretation. The issues and pitfalls involved in representing the geometry of discrete, seismically mappable faults have been discussed in the previous section. In principle, every fault that can be identified on 3D seismic can be mapped in three dimensions and characterized for flow simulation purposes. In practice, of course, inherent limitations of seismic data resolution mean that only the largest faults can be mapped as discrete objects. For example, very high quality seismic may permit faults with throws down to *c.* 5–10 m (and lengths of hundreds of metres) to be mapped, but a decrease in seismic quality could mean that faults with throws of *c.* 30–40 m may not be resolvable.

In a general sense, the fault system can be subdivided into faults that are large enough to be visible and mappable from offset of reflectors, and the smaller faults that have more subtle seismic signatures that can sometimes be mapped from 'attribute' lineations on seismic reflectors (bedding horizons) using various amplitude variation and discontinuity detection techniques. Thus, in the absence of clear reflector offsets, the smaller faults are seen where amplitude becomes dimmed due to net destructive interference of diffracted seismic energy at the fault scarps (see Townsend *et al.* 1998 for discussion), and where horizon dip and dip azimuth changes sharply. Some of the latter attribute types assume that bedding is approximately planar or gently curved and that lines along which reflector dip changes rapidly are the 'smeared out' response to a fault too small to resolve as a discrete object. Others use wavelet correlation techniques to detect a change in seismic character, tracking along a single horizon or in time-slices or a 3D volume. In the first case the discontinuity detected is Horizon A – Fault – Horizon A; and in the second case, Horizon A – Horizon B. Most seismic workstations and many geomodelling software packages have tools such as coherency (Bahorich & Farmer 1995), dip, edge-detection or semblance (Marfurt *et al.* 1998) available; indeed they are routinely used as interpretation aids in the early stages of defining seismically resolvable faults (e.g. Jones & Knipe 1996; Townsend *et al.* 1998). Care needs to be taken, however, to filter-out erroneous interpretations where seismic quality is sub-optimal, since some 'semi-automated' methods are capable of picking noise in addition to 'real' faults in the data (Hesthammer *et al.* 2001). It is a natural extension of this process to use these techniques to define subseismic lineaments.

Curvature of seismically mapped surfaces can also serve as an edge detection tool, with hanging wall and footwall cut-offs corresponding to parallel bands of negative and positive curvature respectively (e.g. Murray 1968; Lisle 1994; Stewart & Podolski 1998). It is advisable to filter the input data spatially, to separate gross structural configuration (long wavelength) from faults (short wavelength), and to enhance the signal:noise ratio and resolution at the target wavelength (Bergbauer *et al.* 2003). Other techniques to enhance the detection of small-scale faulting include shaded illumination, dip-azimuth and directional curvature (extracted along parallel, vertical observation planes). Some techniques are optimally sensitive to faults with particular azimuthal orientations, and care must be taken to ensure that preconceived ideas about the fault trend do not lead to a failure to detect faults with an unanticipated orientation.

Practical limitations on the time allocated for interpretation and the requirement to construct a computationally tractable model commonly lead to simplifications or omissions in the final model. Jolley *et al.* (2007) and **Fisher & Jolley** have shown how careful thought about the flow implications of a particular simplification can lead to better designed models, given the same data and model size restrictions. They also show that time spent in getting the starting model right is more than repaid by the reduced reservoir engineering effort required to generate a robust, history-matched flow simulation model.

Fault network geometry

Fields with only 2D seismic or outcrop data require much more interpolation and have increased ambiguities around fault geometry and linkage. Rules of thumb often come into play then, perhaps informed by analogue data from fields with 3D seismic, from well-exposed outcrops or from laboratory-scale models and kinematic or geomechanical modelling studies. The balanced cross-section approach (e.g. Dahlstrom 1969; Gibbs 1983) aims to constrain the structural interpretation to one which is kinematically self-consistent, by retro-deforming the current geometry to a plausible initial condition and then replicating the current geometry through a plausible forward deformation path. Software implementations of this approach are available in 2D and 3D modelling packages which link fairly seamlessly with seismic interpretation and simulation grid building packages. Typically, these assume that displacement is concentrated on the mappable faults, with intervening fault blocks deforming passively as they are carried on the faults. They also commonly assume constant displacement and slip directions on each fault segment, with discontinuous changes in displacement taking place at fault linkages or branch lines. This model is, of course, a simplification and an alternative view of the fault linkage in a system, which is supported by 3D seismic data and by closely spaced 2D observations in mines and quarries, is that displacement variation along fault planes is the norm and that displacement transfer can be accommodated by deformation of the intervening rock volume. These alternative models for fault linkage, referred to as hard- and soft-linkage, may generate a very different level of fault connectivity (Fig. 2; cf. Walsh & Watterson 1991). These two end members will display very different flow behaviour, with Figure 2a being more connected than Figure 2b if the faults are conductive, but less connected if they are sealing.

Although there is inherent complexity in the variation of natural fault displacement, mapping measurable displacement components such as fault throw, onto fault-plane-projection 'Allan' diagrams (Allan 1989), can provide constraints and quality control checks on the interpretation (Barnett *et al.* 1987; Badley *et al.* 1990). A common assumption is that gradual displacement

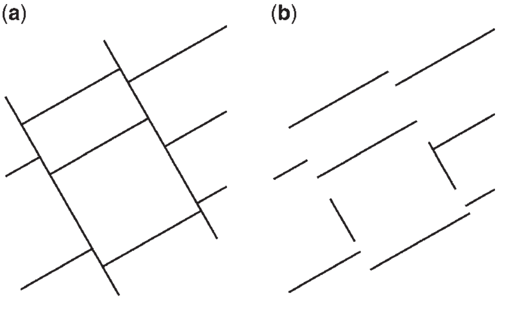

Fig. 2. Alternative map interpretations of sparse fault observations, e.g. on 2D seismic lines. (**a**) A connected (hard-linked) end-member with displacement changing only at fault intersections and a trellis-like fault network. (**b**) A disconnected (soft-linked) end-member with displacement varying continuously across the fault planes and decreasing to zero at the fault tips.

variation is expected of a simple fault, but abrupt changes in displacement imply the presence of a fault intersection or branch line, even if there is currently no intersecting fault mapped at that location (Badley *et al.* 1990; Needham *et al.* 1996; Nicol *et al.* 2002). Modern seismic and geological interpretation packages typically have some ability to display Allan planes, contoured with appropriate parameters, but the facility is not as widely used as it might be. Even 3D seismic has hidden connectivity issues which can benefit from the same interpretation approach as 2D data. For example, fault planes are rarely imaged directly on seismic cross-sections and have to be interpolated between bedding offsets; and interpretation typically begins on a grid of seed lines with the major faults being embedded in the model early as explicit, manually connected features. However, faults can be isolated features and die out downwards as well as upwards (e.g. Barnett *et al.* 1987; Walsh & Watterson 1991; Cartwright 1994), or merge into a décollement surface or ductile zone such as salt or overpressured shale (Cartwright 1994; Jackson 1995; Watterson *et al.* 2000). Whatever the origin or nature of fault displacement variations, failure to define the geometry and connectivity of faults properly may in fact be one of the main sources of error in the modelling of structurally complex reservoirs, despite the fact that fault mapping now benefits from a variety of supporting techniques.

The possibility that fault mapping could unhinge a significant number of reservoir studies may reflect the inherent pressures on geologists and geophysicists, to create the definitive ‘top reservoir map’ rapidly, when a more measured and discriminating 3D mapping approach would represent the best means of defining the basic geometry of faulted reservoirs. Failure to recognize the importance of basic fault mapping in 3D can introduce spurious connections or offsets of stratigraphic models. Even where the reservoir geometry is mapped accurately it is also possible that it is not represented accurately in the 3D simulation grid. However, techniques are available in 3D modelling packages to reproduce important fault-related geometrical features faithfully, such as the 3D variations in fault displacement, the geometries of fault intersections and the presence of fault discontinuities (e.g. relays). If these are not applied consistently, they may introduce unavoidable computational penalties to the model and may compromise later fault property modelling (e.g. some geometrical solutions to so-called ‘Y-fault’ geometries involve severe discretization and aliasing of faults). **Hoffman & Neave** discuss the advantages and limitations of some 3D fault modelling approaches in common use today.

Subseismic scale faulting

As well as being used to define discrete faults, seismic data, particularly 3D seismic, can be used to detect smaller fault and fracture distributions. Simple seismic attributes responsive to surface roughness at a scale too small to be resolved individually include coherency and its relatives (discrete faults give rise to linear features, whereas background faulting or fracturing generates a broad zone of low coherency) and reflection amplitude (small-scale faulting produces waveform interference and scattering of the seismic energy which dims the amplitude). By their nature these attributes are insensitive to whether the fractures are conductive or sealing. More sophisticated attributes are available with multicomponent and multidirectional seismic acquisition, which allows measurements of seismic anisotropy (Verwest 1994; Bouska & Johnston 2005). A directionally anisotropic seismic response is strongly suggestive of open fractures, because the seismic response of a closed fracture or granulation seam is only subtly different from that of matrix, but that of an open fracture is very different, especially if it is filled by a compressible fluid such as oil or gas.

The simplest measure is velocity anisotropy, where seismic rays travelling across an aligned fracture set are slower than those travelling parallel to the fractures (Crampin 1981; Hudson 1981; MacBeth 1995). Multidirectional or orthogonal fracture sets can give rise to an isotropic seismic response, but it may still be possible to infer fracture presence if the velocity is anomalously slow in all azimuths. Obviously that requires a meaningful definition of ‘anomalously low’, and may not be possible where there are large matrix velocity variations due to fluid or lithology effects. Fracture predictions based on seismic anisotropy and coherency-like attributes have been presented by, for example Bloch *et al.* (2003) and Barr *et al.* (2007). Calibration against core or image log data is advisable (e.g. Smith & McGarrity 2001) and proof-of-concept may be necessary before committing to a 4C OBC survey.

More sophisticated approaches involve shear wave splitting (e.g. Winsterstein 1989; Owen *et al.* 1998; Maultzsch *et al.* 2003) and seismic amplitude variation with offset and azimuth (AVOA; Lynn & Thomsen 1990; Hall & Kendall 2003). **Kendall *et al*.** show that the magnitude of the seismic response in the Clair field, west of Shetland, depends not only on the fracture anisotropy but also on the matrix anisotropy introduced by bedding and mineral grain alignment. The seismic rays at large source:receiver offset travel at an angle to bedding rather than perpendicular, and therefore ‘see’ a combination of fracture and matrix anisotropy. **Kendall *et al*.** therefore devoted considerable effort to matrix characterization, as a necessary precursor to seismic fracture prediction. They find an AVOA response between thin-bedded and massive sandstone units which is different in fractured and unfractured cases, even with the same fracture intensity in each unit, and thus they can distinguish between cases where the upper or lower unit is the more fractured.

The two end-member geometries in Figure 2 have very different strain distributions *between* and *around* the faults. This strain distribution is important because it provides a potential entry-point to the geomechanical prediction of subseismic faults and fractures, which can enhance or retard flow depending on whether they are more or less conductive than their host rock. Most faults are surrounded by a 'damage zone' tens of metres wide, comprising subsidiary faults and fractures (Antonellini & Aydin 1994; McGrath & Davison 1995; Caine *et al.* 1996; Knipe *et al.* 1997; Foxford *et al.* 1998; Beach *et al.* 1999; Hesthammer *et al.* 2000; Billi *et al.* 2003; Berg & Skar 2005). In this context damage refers to a change in the effective bulk properties of the rock caused by a swarm of small-scale structures and may cause flow enhancement or retardation (a drilling or production engineer will often restrict the term damage to flow retardation). In addition, the volumes between the faults have typically suffered volumetric or shear strain, perhaps related to bending during accommodation to the fault surface (e.g. Nicol *et al.* 2002; see also papers in McClay 2004) or to satisfy compatibility contraints as displacement dies out in a soft-linked fault array (e.g. Fig. 2b, Barnett *et al.* 1987; see also Hedland 1997; Soliva & Benedicto 2005). There may also be a systematic distribution of subseismic faults related to the large-scale structures. These can have a simple relationship to the major faults (e.g. antithetic in the hanging wall). If their distribution is unpredictable or poorly understood they can be modelled stochastically by assuming or observing a size, frequency relationship such as a fractal or power-law distribution and extrapolating downscale (Childs *et al.* 1990; Gauthier & Lake 1993; **Mäkel**). There are potential pitfalls in the analysis of such data (Heffer & Bevan 1990; Cowie *et al.* 1996; Yielding *et al.* 1996; Belfield 1998) and it is only meaningful within a genetically related range of structures. Subseismic faults might reasonably be extrapolated downscale from seismic faults but in circumstances where mechanical stratigraphy exercises a strong control on the fracturing process, fault or fracture systems may not have fractal geometries and the notion of extrapolation of fault size distributions could be flawed (see Nicol *et al.* 1996 and Soliva & Benedicto 2005 for discussion). This scenario almost certainly applies to stratabound joints even in circumstances where they have a component of shear displacement and may display some fractal characteristics (e.g. Odling *et al.* 1999; **Barr**). Finally, the mapped fault tip locations are themselves limited by seismic resolution. Where displacement:-distance relationships are well defined (e.g. Walsh & Watterson 1987; Cowie & Scholz 1992) it is possible to extrapolate the fault beyond the seismically resolved location to a predicted tip-line, based on the observed rate of displacement loss where it is still seismically observable (Yielding *et al.* 1996; Rutten & Verschuren 2003). Similarly, the width and internal geometry of fault damage zones has been well characterized in numerous outcrop analogues (Antonellini & Aydin 1994; Hesthammer *et al.* 2000; Billi *et al.* 2003; Odling *et al.* 2005) and can be predicted by selecting the right analogue and control parameters such as fault displacement and host-rock lithology. Once the geometry and petrophysical properties of the small-scale features are defined (see below), their flow implications can be simulated by explicitly modelling the observed fractures or a stochastic representation of them (Heath *et al.* 1994; Manzocchi *et al.* 1998; Walsh *et al.* 1998; Harris *et al.* 1999, 2003, this volume).

Strain modelling and fracture prediction

Perhaps less widely acknowledged is the fact that two identical mapped fault networks can have different bulk strain distributions—although it has long been taught in structural geology textbooks that there are many potential paths to a particular deformed state (e.g. Hobbs *et al.* 1976, p. 32). If a record of the strain history during progressive deformation is preserved it may be possible to distinguish between alternative deformation paths (e.g. Ramsay 1967 p. 119–120). **Lewis *et al*.** demonstrate with a simple example how very different deformation paths resulting in very different internal strain distributions can produce identical-seeming fault and horizon geometries. Structural modelling software is available and under development which tracks the deformation history of the fault blocks (i.e. 'kinematic restoration') during the forward modelling step. Such models are non-unique, but they can yield valuable insights into potential subseismic deformation. In some software packages the non-uniqueness is exposed to the user, in that explicit kinematic choices have to be made about the fault-slip and inter-fault deformation mechanism; in that case it should be obvious that a matched result is a possible but not unique solution. But the more automated the process, developed perhaps in the interest of broadening the pool of potential practitioners beyond structural geology specialists, there is a greater risk of users assuming that the result must be right 'because the model says so'.

Notwithstanding these limitations, considerable effort is currently devoted to developing techniques to predict fracture and small-scale fault distribution at a scale much less than seismic resolution and comparable to that of core or well logs. Typically these will be predictions of the 'joint-like' rather than 'fault-like' populations. The joint-like population includes shear fractures or granulation seams as well as tension fractures—essentially those features that are small and dispersed enough to form components of an effective medium at the scale of observation, rather than discrete entities. Long-wavelength curvature can be used as a strain predictor (e.g. Stewart & Podolski 1998) with the expectation that outer-arc extensional strains will be associated with open, tensile fractures. Use of this flexural beam model requires the correct choice of mechanical layering and identification of the neutral surface. Fractures would be predicted in synclines below the neutral surface as well as in anticlines above the neutral surface. Caution is advised in interpreting the output maps, as many existing approaches make potentially unacceptable simplifying assumptions (see Bergbauer & Pollard 2003 for review). Combinations of curvature attributes can be used to define a 'shape curvature' (Bergbauer *et al.* 2003), which classifies a mapped surface (at a particular wavelength) into anticlines, synclines, domes, basins etc. Shape curvature may be a predictor of fracture style rather than fracture intensity (e.g. orthogonal v. conjugate v. unidirectional, or shear v. tensile). **Bergbauer** describes an outcrop example of a fold where curvature shape and magnitude were poor predictors of fracture orientation and intensity but good predictors of fracture style. In this case, fractures developed within the relatively slab-like limbs are passively rotated and propagate along their axes, whereas additional strains at the curved fold hinge have reactivated fractures in shear. Indeed, **Ferrill *et al*.** describe the deformation within a monoclinal fault propagation fold, in which they find flexural shearing of well-bedded stratigraphy in the mid-limb has re-worked earlier formed fractures, such that in this case, fracture style is related to dip domain. Both papers emphasize the role of mechanical stratigraphy in governing the underlying deformation processes.

Geomechanical models, typically discretized using finite element or boundary element techniques (Crouch & Starfield 1983), go beyond simple curvature. These use elastic (e.g. **Wilkins**) or more complex, elastic–plastic, constitutive laws to predict the stress and strain distribution between mapped faults. The situation is at its simplest where the structure in question formed as a result of a single episode of progressive deformation. In that case it may be acceptable to approximate the driving stress or strain state by that required to deform an initial bedding configuration to the current field geometry. Predicted elastic strains are often scaled, to compensate for the fact that deformation was intermittent with some relaxation of elastic strain and accumulation of permanent strain between increments (e.g. **Wilkins**). More sophisticated constitutive laws such as the elastic–plastic one used by **Lewis *et al*.** attempt to model the progressive evolution of permanent strain through a deformation cycle. Refinements used include variable treatment of fault mechanics (purely frictional v. more complex formulations where some faults are effectively given finite strength) and the introduction of compaction, fluid pressure and gravity effects. An alternative approach where the deformation history is too complex to unravel or represent, is simply to model the present day stress state, treating the reservoir as a relatively homogeneous body of rock dissected by weak faults which locally perturb the far-field stress trajectory; an approach similar to that used in earthquake modelling. Stress perturbations and interactions around faults can be used to predict stress trajectories between faults (from which favoured open fracture orientations can be deduced), or to high-grade as potentially conductive those faults which are closest to a frictional failure criterion. Attempts are now being made to track strain evolution through complex deformation episodes (e.g. Dunbar & Cook 2003; Maerten & Maerten 2006), which in principle allows better control of fracture initiation and subsequent modification. The geomechanical models can be used to help define the displacement history (i.e. geomechanically based structural restoration, e.g. Maerten *et al.* 2006) or the displacement history can be extracted from a kinematic structural restoration and used as boundary condition inputs to a geomechanical model (e.g. Lewis *et al.* 2004).

The end-point of such modelling is rarely the prediction of individual fracture formation, except for those subseismic faults that are large enough to implement in a 3D reservoir simulation model. More typically, dilational strain is taken as an open fracture indicator and compactional strain as a closed fracture indicator. The magnitude and orientation of the principal stress or strain axes are used to constrain fracture orientation, type and intensity (**Mäkel; Wilkins**). The constraint can either be deterministic, via empirically defined lookup tables or correlations to well data; or stochastic where the geomechanical model outputs are used as constraints on a discrete fracture network which is then upscaled to effective flow properties in a reservoir simulator (e.g. Sabathier *et al.* 1998). An important modelling decision is whether to calibrate directly to static well and seismic observations, or to bypass those and calibrate directly to dynamic, reservoir engineering observations (e.g. **Barr**). An argument in favour of the latter approach is that the fracture description is a means to an end and that end is populating a reservoir simulation model. Ultimately, the fracture description has to be upscaled to effective cell properties (e.g. Bourbiaux *et al.* 1997), a step that introduces its own set of assumptions and uncertainties. In addition, the fractures in a vertical well may be unrepresentative even of the surrounding (say) 100 m × 100 m grid cell area. A weakness of direct dynamic calibration is that it introduces an empirical step involving poorly defined or understood processes. If the next well fails to match predictions, there is little chance of understanding why, and it will likely be handled by making another poorly understood empirical adjustment. **Hall & Lewis** attempt to introduce some rigour into this process, by placing seismic and geomechanical attributes on a common descriptive footing, as an effective medium sampled at the target reservoir simulation scale.

Fault compartmentalization

Faults transecting siliciclastic reservoirs in which the reservoir units have high porosities and permeabilities generally act as baffles or barriers to flow. In these circumstances, following the 3D mapping of seismically imaged faults and, sometimes, the prediction of subseismic faults, the next major step is definition of fault properties and their incorporation within reservoir models, either as transmissibility multipliers on individual faults, or as upscaled effective permeabilities, in the case of subseismic faults. Here we describe the technical issues and methodologies associated with this phase of the structural geology workflow.

Fault zone properties

Natural fault zones are characterized by three-dimensionally complex juxtapositions and displaced lenses of host stratigraphy, and modified porosity-permeability variations within the suite of different fault rock products and fracture arrays that the zones usually contain (e.g. Knipe 1993, Childs *et al.* 1997, *this volume*; Knipe *et al.* 1997; Foxford *et al.* 1998; Fisher & Knipe 1998, 2001; Gibson 1998; Ingram & Urai 1999; Skerlac 1999; Sperrevik *et al.* 2000; Aydin & Eyal 2002; Jourde *et al.* 2002; Berg & Skar 2005; Eichhubl *et al.* 2005; Shipton *et al.* 2005; van der Zee & Urai 2005). However, there are significant hurdles to overcome in predicting the distribution of these lithological fragments and fault rock properties within a fault zone, from the often sparse information available to field appraisal and development teams. It is well known that clay content plays a significant role in reducing permeability in fault rocks developed within siliciclastic rocks (e.g. Fisher & Knipe 1998, 2001; Manzocchi *et al.* 1999; Sperrevik *et al.* 2002). Consequently algorithms have been developed which attempt to calculate the distribution of average clay content (and therefore the general permeability distribution) within fault zones—from the reservoir properties, clay content and shale bed distributions within the adjacent stratigraphy—at a similar scale to that of a typical simulation model fault (cf. Yielding *et al.* 1997; Doughty 2003). As discussed by **Fisher & Jolley**, at the modelling stage many of the predictive algorithms are based on the input of ‘clay contents’ derived from geophysical well log data—and care is therefore needed to account for uncertainties in petrophysical calculation of the ‘shale’ or ‘clay’ content measures (V_{Shale}, V_{Clay}), and to ensure that these results are compatible with independent measures of clay content (often taken from core samples). The three most commonly used algorithms, developed over a decade ago, use some of the basic processes which entrain clay minerals and discretely bedded shales into a fault zone (Fig. 3). Thus, Shale Gouge Ratio (SGR, Yielding *et al.* 1997) is based on mechanical mixture of shaley material within a fault gouge, assuming that the resulting fault rock/gouge clay content approximates to the average collective stratigraphic clay content which has been displaced past any given point on the fault. The Clay Smear Potential (CSP, Bouvier *et al.* 1989; Fulljames *et al.* 1997) predicts the length continuity of a shale bed plastically smeared into the fault from the fault throw and source shale bed thickness. The Shale Smear Factor (SSF, Lindsay *et al.* 1993) focuses on predicting the thickness continuity of smears caused by ductile smearing and abrasion of shales and also as a function of throw and source shale bed thickness.

In some situations, for example where shale and/or sand beds are relatively thin, it can be argued that clay smears are accounted for within the SGR algorithm, once stratigraphy is upscaled. Where the shale layers are thicker, the smears can become more robust and continuous, such that they preserve stratigraphic compartmentalization despite the faulting but the detail of this is not captured by SGR. Consequently, several proprietary algorithms have developed within the industry as a spin-off from these basic SGR/CSP/SSF forms, mostly in an attempt to integrate them into a harmonic averaging tool for predicting fault zone clay content. **Childs *et al*.** provide an important

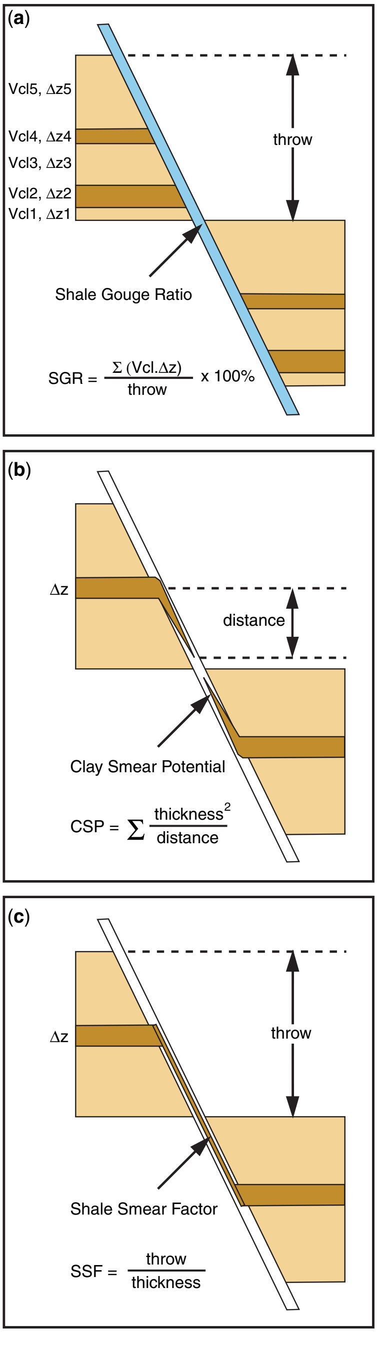

Fig. 3. Fault seal algorithms, commonly applied in low/mid net-to-gross (mixed sand-shale) reservoir stratigraphies. (**a**) Shale-Gouge-Ratio (SGR; Yielding *et al.* 1997), (**b**) Clay-Smear-Potential (CSP; Bouvier *et al.* 1989; Fulljames *et al.* 1997), (**c**) Shale-Smear-Factor (SSF; Lindsay *et al.* 1993). From Jolley *et al.* (2007), modified from Yielding *et al.* (1997).

dataset in this regard, which shows that clay smears can become disengaged from their source layers, to form 'slugs' within the fault zone. Their outcrop observations on faulted New Zealand turbidites do not support a systematic arrangement of clay smears in relation to their source beds, and so they have developed a stochastic approach to distribute the smears within the fault planes, which they term the probabilistic Shale Smear Factor (PSSF). An interesting outcome of such a model is to provide effective properties at high throw to bed thickness ratios, which are indeed similar to other approaches, such as SGR. This work therefore provides a rationale for the successful application of these approaches, even though the deformation mechanism which it implicitly assumes may not be correct. Similarly, detailed modelling of fluid flow through a realistic representation of fault damage zones by **Harris *et al*.** supports the conclusion that the simpler, commonly used approach of harmonically averaging volume-weighted fault-rock permeability, is a useful first approximation in assessments of the flow impact of subseismic faults (Walsh *et al.* 1998).

The prevailing stress and temperature during deformation also controls the degree of grain breakage (cataclasis) and crystallization of some cementation types, and consequent permeability collapse within the fault zone (Knipe 1989; Zhang *et al.* 1990; Wong *et al.* 1997; Chester & Chester 1998; Fisher *et al.* 2000, 2003). Thus, despite the popular view from the usage of clay-content algorithms in fault seal analysis described above (that low clay content faults developed in sand-rich reservoirs do not seal), under the 'right' conditions and geohistories, sealing on a production timescale is also possible in low clay content fault rocks. Where there is a strong palaeotemperature gradient across a field or cluster of fields, this can lead to profound differences in fault compartmentalization and consequent production characteristics (e.g. Hesthammer *et al.* 2002). However, these low clay content cataclastic seal types can become brittle, damaged and leaky if a field is subsequently deformed under different stress and lower temperature conditions (e.g. Leveille *et al.* 1997). **Barr** gives a detailed description of the complex distribution of fault seal compartmentalization, and conductive faults and open fracture systems in the sand-rich aeolian reservoirs of the West Sole gas fields. He shows that sealing lithified cataclasites formed in fault zones during an early rifting phase at high pressures and temperatures with some influence from host sediment facies type on crystallization of certain cementation phases; and that open seal-breaching fracture systems developed during later contractional inversion and fault reactivation at lower pressures and temperatures. In general terms the sealing and open structures tend to be mutually exclusive. Although data resolution and a significant element of clustering or selectivity in the reactivation processes introduce technical difficulties, it has nevertheless been possible to use this model to detect reactivation and therefore predict the general distribution of intact and breached seals and/or open fracture networks within the fields.

Static fault seal prediction

Exploration projects commonly use a deterministic approach to 'map' fault zone properties, such as SGR, within a fault plane and thereby calculate the predicted hydrocarbon columns that can be accumulated and held by sealing faults over geological time (e.g. Yielding 2002). These methods are based on explicit modelling of reservoir and non-reservoir juxtapositions and the sealing properties of fault rocks. However, James *et al.* (2004) suggest that static fault seals are controlled exclusively by juxtaposition, and they describe a stochastic approach to fault seal analysis, which models variation of stratigraphic stacking across a fault to assess its hydrocarbon retention capacity. An energetic debate has since developed on the conference circuit between proponents of these two radically differing approaches. **Dee *et al*.** use the data presented by James *et al.* (2004), in order to compare and contrast the results that are achieved by these two radically different methods on the same dataset. They compare the stochastic analysis with a standard SGR-based approach and suggest that despite the conceptual differences between the deterministic and stochastic methods, the results are remarkably similar. This study therefore appears to provide another useful validation of a widely applied 'rule of thumb'.

Production fault seal modelling

Under production conditions lower permeability fault zones will generally lead to the compartmentalization of pressure distributions, hydrocarbon saturations and contacts across the faults. Fault property modelling under these conditions therefore attempts to define the rate of fluid flow across the faults in order to quantify the connected petroleum volumes that can be accessed by any given well or group of wells. Numerical flow simulation models including the effects of fault properties are now routinely used to guide field development, production management and well planning decisions (e.g. Dake 2001). The reliability of the 'prediction mode' of a model is generally tested by comparing the match between actual historical production data and the simulated production history, the so called 'history match'. In detail, the fluid flow between adjacent cells in a standard simulation model is expressed by the cell-cell 'transmissibility' (a function of the geometry and permeability of the cells). The reduced permeability of an intervening fault is accounted for by correcting the cell–cell transmissibility with a fault transmissibility multiplier, a function of fault rock thickness and permeability (Fig. 4; e.g. Knai & Knipe 1998). However, although the stratigraphic controls on field compartmentalization are routinely addressed within generally accepted geologically-rationalized tools and workflows, it has been an industry-wide experience that the flow retarding effects of the faults are treated in an *ad hoc* manner by the reservoir engineer, late in the workflow. It is possible to achieve a history match by using the production data to guide manual application of geologically unrealistic faults and fault properties to steer flow and pressures around the model in this way. However, this is likely to be an artificial compensation for other inadequacies and uncertainties in the model, which then become obscured by this activity (**Fisher & Jolley**). It follows that the more of these trial-and-error amendments there are in a model, the less likely it is that its simulated flow approximates to reality (despite the history match) and consequently the 'prediction mode' becomes unreliable. Such structural uncertainty can seriously impact field development planning and production management (e.g. Corrigan 1993; Lia *et al.* 1997). However, as described below, data, tools and methods have evolved in recent years to permit more valid, systematic incorporation of fault properties within simulation models.

$$TM = \frac{TransF_{ij} = \left(\dfrac{2}{\dfrac{L_i - t_f}{k_i} + \dfrac{2t_f}{k_f} + \dfrac{L_j - t_f}{k_j}}\right)}{Trans_{ij} = \left(\dfrac{2}{\dfrac{L_i}{k_i} + \dfrac{L_j}{k_j}}\right)}$$

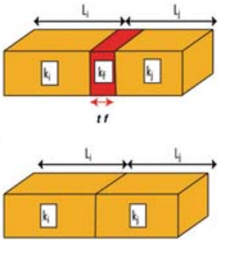

Fig. 4. Fault transmissibility multiplier (TM) calculation between faulted cells of a simulation model. These calculations differ in detail between simulation software packages and this cartoon (from Jolley *et al.* 2007, modified after Manzocchi *et al.* 1999) ignores cell dip terms and assumes net:gross ratios and intersection areas of 1.0.

Incorporating fault properties in production simulation models

The fault seal algorithms described above provide the building blocks for inclusion of fault properties within simulation models. For example, Manzocchi *et al.* (1999, 2002) provided robust methods with which it is possible to invoke these algorithms, to incorporate the flow-retarding effects of faults systematically. Their methods calculate geologically realistic fault transmissibility multipliers from the upscaled model geometry and geo-cellular properties (e.g. stratigraphic distribution of clay, porosity, permeability). Thus, fault rock clay content prediction methods (e.g. SGR/CSP/SSF and other similar algorithms) can be calculated from the reservoir geometries and properties implicit within the geo-cellular cornerpoint grid of a simulation model. The first-order sensitivity of a simulation to structural influence is caused by juxtaposition of flow units and non-flow units across the faults, since this affects the basic 'plumbing' within the model. **Hoffman & Neave** and **Tertois & Mallet** discuss some of the pitfalls, procedural limitations and potential solutions to the necessary compromises that are made in constructing a 3D fault model from seismic data and the subsequent simulation grid. Thus, geometric flaws introduced at that stage result in inappropriate layer juxtapositions in the cellular model, and also restrict the geologist's ability to properly represent fault zone properties. Constraints on simulation cell geometry, driven by a desire for simple flow formulae that can be solved by existing technology in a commercially useful timeframe, can introduce compromises in fault representation since it is typically the faults that contribute most geometrical complexity to the model. However the validity of flow simulation models (and therefore the reliability of their results) can be improved vastly through inclusion of geologically realistic faults, integrated with systematically calculated fault zone properties (e.g. Jolley *et al.* 2007; **Fisher & Jolley**). In this approach, SGR and/or an SGR/smear algorithm combination can be calculated and used as a proxy for fault rock clay content and integrated with fault rock permeability data to systematically assign fault transmissibility multipliers within simulation models (*sensu* Manzocchi *et al.* 1999). **Myers *et al*.** provide a case study from a North Sea fluvial reservoir in which the history matches obtained from simulation models are progressively improved by incorporating increasingly realistic fault geometries and stratigraphic architectures. This incremental approach helped to narrow the uncertainty range on fault properties applied to faults in the simulation. Jolley *et al.* (2007) found that provided a geologically valid model was transferred to the simulator, the best history matches were then achieved in a fraction of the usual project time by integrating fault rock property data acquired from drill cores obtained within and close to a given reservoir to calculate the multipliers. This was particularly the case where the sampled fault rocks had experienced a similar stress-temperature (burial) history to that of the study reservoir.

Modelling interaction between faults and stratigraphic complexities

Fisher & Jolley review the wide-range of uncertainties associated with the data acquisition and processing, interpretation and modelling phases of the fault property modelling workflow. Additionally, limitations within the generally available modelling technology, force a tension between efforts to capture and preserve the geological information which is critical to fluid storage and flow, and efforts to distil the geology down to more basic elements in order to satisfy a simulation model's computational memory budget. Care therefore needs to be exercised when characterizing and simplifying stratigraphic details to assign average properties to model cells, as this can disengage continuous depositional features and/or introduce erroneous connections between layers in a model (**Myers *et al*.**). For example, it is a common experience that actual flow connectivity within a reservoir is less than that implied by a geo-cellular model of the field. As **Fisher & Jolley** point out, these effects are frequently assumed to be caused by sealing faults, leading to erroneous *ad hoc* edits being applied to the structure of the model. There is an alternative, entirely logical explanation for these effects—since the averaging of thin shale beds into a net:gross value for each cell, and the stacking of these cells within the model, can overlook the compartmentalizing effects of relatively thin shale layers between sand bodies, unless these shale layers are explicitly modelled. Despite the obvious interdependence between faults and stratigraphic complexities in controlling compartmentalization, there have been few published attempts to characterize the interplay between these elements directly (e.g. Ainsworth 2006). **Manzocchi *et al*.** use a comprehensive suite of faulted and unfaulted models of sheet-like turbidite deposits, to examine the interplay between stratigraphic elements, faulting and fault zone properties using the PSSF method developed by **Childs *et al***. Instead of using the more traditional cellular modelling methods and net:gross ratio to build their models of sand and shale distribution, **Manzocchi *et al*.** have developed a bed-scale modelling method which explicitly includes a measure of sand body connectivity, known as the amalgamation ratio. Compared to data collected from outcrops of similar turbidite deposits, this method was found to give a far more realistic stratigraphic architecture and interbed connectivity in the models. Describing their results in terms of percolation theory, they found that high net:gross sheet turbidite sequences can be very poorly amalgamated/connected. In those circumstances, the introduction of arrays of subseismic faults ($<$ *c*. 5 m throw) only reduces the connectivity within models under a rare combination of circumstances and in some situations, the relative influence of faults and stratigraphic elements on flow connectivity in the models were indistinguishable.

Multi-phase flow properties of faults

Given the very small pore throats which characterize many fault rocks, water-wet faults (i.e. those having a water film coating all the grain surfaces in the fault rock and thus impinging on its available pore space) have such high water saturations close to the free water level (FWL) of a reservoir that they may have negligible relative permeability to hydrocarbons. At some distance above the FWL the buoyancy force in the hydrocarbon column may be sufficient to overcome the capillary threshold pressure of the fault rock, giving it a finite relative permeability to hydrocarbons, and thus permitting cross-fault flow of oil or gas (for discussion see Fisher *et al.* 2001; **Fisher & Jolley**). Traditionally, the multi-phase flow properties of faults have not been included during production simulation modelling, although several key publications have highlighted their importance (e.g. Manzocchi *et al.* 1998, 2002; Manzocchi 1999; Fisher & Knipe 2001; Rivenæs & Dart 2002; Al-Busafi *et al.* 2005). A recent innovation in fault handling within reservoir models is the development by Manzocchi *et al.* (2002) of a method for the inclusion of the two-phase flow properties of faults. Because two-phase properties, unlike single fluid phase properties, cannot be attached to the face of grid blocks in reservoir simulations, this method derives pseudo-relative permeability functions including the fault rock properties in the upstream grid block for cross-fault flow. This method incorporates the saturation and flow rate dependencies of two-phase flow and is a fairly comprehensive treatment of the problem. **Zijlstra *et al*.** present flow data from a number of faulted reservoirs suggesting that two-phase flow properties of the faults are important in controlling compartmentalization of fluid production. They support their conclusions by presenting the results of a method for fault property modelling which is easy to implement and accounts for some of the effects of fault-related single phase and multiphase flow (as described by Manzocchi *et al.* 1999, 2002).

Upscaling the flow effects of subseismic faults

The recognition that subseismic faults could have an impact on flow within siliciclastic reservoirs, has only recently been matched by the development of methods which provide a basis for their incorporation into flow simulation models. Typical approaches involve definition of the upscaled effective properties of subseismically faulted rock volumes, with their eventual implicit inclusion in reservoir simulations. Early work showed that for typical fault densities and geometries (including connectivities), subseismic fault arrays will generally only begin to have a significant impact on flow within reservoirs (i.e. decreasing effective permeabilities by more than *c*. 20%) when fault rock permeabilities are at least two orders of magnitude below those of the reservoir host rocks (e.g. Manzocchi *et al.* 1998; Walsh *et al.* 1998). For less permeable fault rocks, cross-fault flow decreases rapidly with an increase in flow tortuousity, until flow is dominated by the connectivity of sealing faults (Walsh *et al.* 1998).

Analysis of the impact of damage zones surrounding seismically imaged faults reveals similar features, with newly developed methods being capable of exploring the sensitivity of flow to the full range of geometric and scaling parameters associated with damage zones (see **Harris *et al*.** and references therein). Harris *et al.* (1999, 2005, *this volume*) extend these sensitivity studies into 3D, and make a strong case for the routine definition of damage zone effective properties and their implicit inclusion in reservoir flow simulations. **Ma *et al*.** show the extent to which modelling of small fault arrays is sensitive to the modelling methods used, including such issues as discretization and the preservation of fault connectivity. Other issues need to be resolved, such as the multiscaling properties of faults, associated upscaling challenges and the incorporation and displacement of stratigraphic architectures. In that respect, the bed scale modelling of **Manzocchi *et al.*** highlights the complex flow sensitivity of faulted sedimentological sequences, a topic which we anticipate will be the subject of future research. Nevertheless, although adoption of associated modelling and upscaling approaches has, hitherto, been relatively slow (with most attention focused on larger seismically imaged faults), recent advances suggest that the incorporation of subseismic faults and damage zones should become relatively routine within the next decade.

Fractured reservoirs

Fractured reservoirs form a special class of structurally complex reservoirs in which hydraulically conductive fractures or faults make a significant contribution to, or dominate, subsurface fluid flow. The interaction between the *storage domain* (typically dominated by matrix lithologies with relatively high pore volume and relatively low permeability) and the *flow domain* (typically dominated by fractures with relatively low pore volume and relatively high permeability) leads to complex fluid and pressure behaviour. This makes it difficult to predict field performance, even assuming a ‘perfect’ understanding of the nature and distribution of the fractures. The problem is compounded by the fact that fracture properties are generally more difficult to characterize than matrix, whether from core, well-log or seismic observations. **Mäkel** provides a detailed review of the issues which need to be addressed in describing and modelling fractured reservoirs, focusing on analysis, description and calibration of the fracture network; that is, up to the point at which the fracture model is upscaled to a simulation grid and ‘handed off’ to the reservoir engineer.

The fractured reservoir papers in this volume supplement a larger collection of papers on this topic, provided in Lonergan *et al.* (2007). More general reservoir engineering and geological aspects of fractured reservoirs are also covered by, for example, Aguilera (1995) and Nelson (2001).

Types of fractured reservoir

Fractured reservoirs are traditionally classified according to the relative contributions of fracture and matrix permeability (e.g. Reiss 1980; Nelson 2001; Allan & Qing Sun 2003; **Mäkel**; Fig. 5). Because of their high conductivity and low pore volume, fractures typically make a large contribution to the flow domain but a small contribution to the storage domain. For a given well or reservoir, a ‘fracture index’ can be defined to represent the magnitude of the fracture v. matrix contribution. For example, the Fracture Productivity Index of Reiss (1980) ratios the well-test *Kh* (average permeability times the height of the tested interval) to the matrix *Kh*; it can be assumed that values much larger than unity reflect a significant fracture contribution. This leads to the interesting observation that ‘how fractured’ a field appears depends not just on the conductivity of its fracture network, but also on that of the matrix properties. For example, the West Sole field (**Barr**) behaves more like a ‘classical’ fractured reservoir than does the Clair field (Barr *et al.* 2007), despite having an effective fracture permeability an order of magnitude smaller. That is because it has two or three orders of magnitude less matrix permeability. Fractured reservoirs typically have very heterogeneous porosity and permeability distributions (**Matthäi *et al.***), which result in characteristic patterns of well performance with most production coming from the best few wells (e.g. Nelson 2001; **Barr**). The worst wells have failed to intersect connected, conductive fractures and a large financial benefit would flow from an ability to target only the best well locations. In practice that requires a robust pre-drilling description of the effective fracture network, hence much industry and academic attention is focused on that objective.

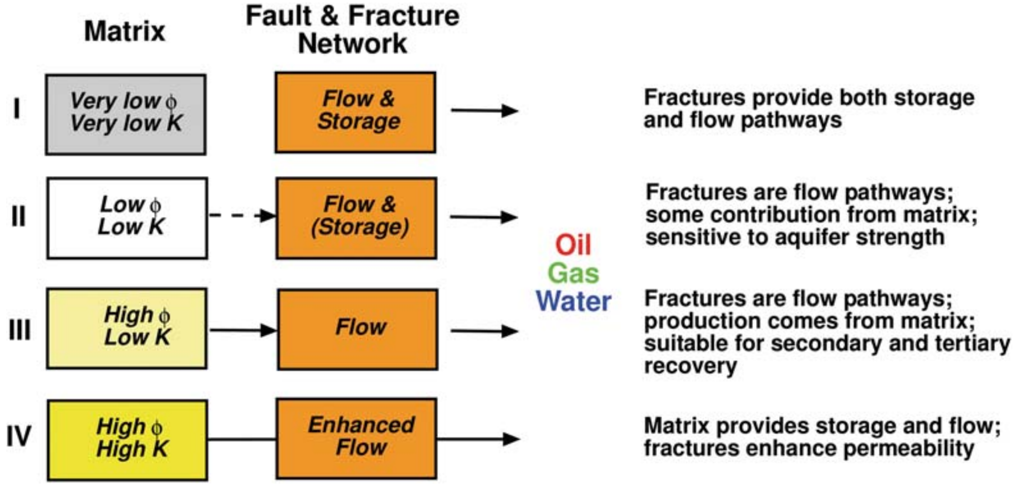

Fig. 5. Schematic representation of the common subdivision of fractured reservoir types based primarily on matrix character (Nelson 2001; Allan & Qing Sun 2003; fig. 1 of Mäkel (this volume).

Fracture detection and description

The recognition of fractures in wells is also dealt with in detail by **Mäkel**. Core is the most definitive source of fracture information and procedures for describing, identifying and classifying them are well established (e.g. Kulander *et al.* 1990) but it is expensive to acquire and there are some data limitations to consider. Drilling, core recovery and sample preparation and handling can all modify natural fractures or create new fractures which must be screened out of the subsurface description. Purely drilling-induced fractures have characteristic features that make them easy to recognize (Kulander *et al.* 1990) but more subtle modifications to the geometry or aperture of pre-existing fractures can be harder to recognize. Open fractures are particularly vulnerable to disturbance because they weaken the rock and the most fractured part of a core may be recovered as uninterpretable rubble. Fractures are likely to have larger apertures at surface than in the subsurface, due to the reduction in effective closure stress, and if the fracture faces can be fitted together perfectly they may have had no subsurface aperture. Most fractures described in reservoirs are not simple planar breaks but have irregular faces and are partially propped or bridged by cementing minerals. Such partially cemented fractures may give the best indication of subsurface aperture and if a genetic link can be drawn between cemented and open fractures, and the cement can be shown to have grown in a single phase, vein widths can also provide a useful indicator (e.g. **Mäkel**). In fields produced by depletion drive, the effective stress acting to close a fracture will increase during production and the most hydraulically effective ones may be partially cemented fractures and shear (or shear-reactivated) fractures with mismatching walls (e.g. **Barr**).

Borehole image logging tools are available that can detect fractures with varying degrees of success (**Mäkel**). All image logging techniques have their limitations and ultimately benefit from calibration against overlapping core and all suffer to some degree from an inability to detect fractures subparallel to the wellbore (**Mäkel**). For those fractures that can be detected, a sampling correction may be made for the intersection angle between fracture and wellbore (Terzaghi 1965; **Mäkel**). Fractures perpendicular to the well will be over-represented relative to fractures oblique to the well and this must be corrected in order to model the 3D fracture density in the surrounding reservoir. However, well productivity may be more influenced by the number of fractures intersected (a well drilled perpendicular to fracture strike will be more productive than one drilled parallel to strike) and uncorrected data may be preferable if that is the objective of the study.

Generally, fracture description and prediction or interpolation in the petroleum industry is not carried out in isolation, but combined with integrated reservoir description and simulation modelling. The process of populating and upscaling a fracture model is conceptually similar to that for a matrix model but generally more difficult and less advanced. Techniques include simple interpolation between wells through conventional geostatistical techniques such as kriging (Olarewaju *et al.* 1997), neural networks (Ouenes & Hartley 2000) and methods which simultaneously incorporate static and dynamic data (Gauthier *et al.* 2002). Much modern effort is devoted to the construction and analysis of a discrete fracture network (DFN) model, in which a stochastically or (rarely) deterministically generated set of fractures is populated into a map or a 3D volume. Stochastic models are typically conditioned on seismic, geometric or geomechanical inputs (e.g. Bourbiaux *et al.* 2002; Maerten *et al.* 2006; Barr *et al.* 2007). **Mäkel** provides a worked example for a dataset comprising three wells. Traditionally, the fracture model has been built independently of the matrix, which can result in unwanted interactions, e.g. open fractures may be modelled in shales where observation shows they are absent. Most modelling packages now offer some ability to condition the DFN on a layer-cake or geo-cellular matrix model, enabling the modeller to control the effect of mechanical stratigraphy better (the influence of matrix lithology, typically some combination of rock-strength parameters, on fracture initiation and growth). Fracture models are typically built at multiple scales, to represent both discrete conductive faults or ‘fracture corridors’ and small, dispersed fractures or joints. Calibration can be at both the full-field scale and the scale of a well test (e.g. Rawnsley & Wei 2001).

Flow modelling and reservoir simulation

The typical situation whereby fractures dominate the flow domain, and matrix the storage domain; means that ideally, fractures and matrix should be kept independent of one another during flow simulation modelling, by use of explicit fracture and matrix cells. The complexity of fracture networks and the sheer number of simulation grid cells required mean that this is rarely done at scales larger than that of a well test, and even then complex models are difficult to represent fully (Basquet *et al.* 2005). The extreme aspect ratios, low pore volumes and large permeabilities of fractured cells also create computational difficulties for simulators optimized to solve problems involving more-or-less cuboidal cells having much the same pore volumes and permeabilities in each. In traditional simulators the simplest solution is to upscale the fractures to effective porosity and permeability at the matrix grid-cell size and merge them with the matrix description. That is successful only in the simplest of cases, typically involving single-phase flow in, for example, dry gas fields without an active aquifer. More complex cases are handled by the dual porosity and dual permeability formulations, in which parallel fracture and matrix descriptions are carried in two identical framework grids, with a transfer function controlling flow between the two domains (Warren & Root 1965; Kazemi *et al.* 1976). The dual porosity approach allows matrix to fracture fluid flow but not the reverse and is suited to cases where matrix permeability is sufficiently low to be neglected. The dual permeability approach allows flow in both directions and is suited to reservoirs with significant matrix permeability, but is much more computationally demanding. The limitations of these approaches are well known (see **Matthäi *et al*.** for a summary), particularly with respect to multiphase flow, and research is in progress to develop better framework descriptions (unstructured grids based on tetrahedral or polyhedral cells rather than cuboids, e.g. **Matthäi *et al*.**; **Tertois & Mallet**) and alternative solver approaches (e.g. **Matthäi *et al*.**).

Stress-sensitive reservoirs and critically stressed faults

Much fractured reservoir description takes a relatively static view of the fracture network and its flowing properties. Geomechanical models are used to predict fracture occurrence much more often than to represent production-induced changes in the fracture network. Where the matrix can be considered unchanging, the elastic response of pre-existing fractures to changing pressure and stress can be measured or modelled (e.g. Jones 1975; Bagheri & Settari 2005). Production-induced fluid pressure changes can do more than just change the aperture of existing fractures by elastic or plastic opening or closing. They can also reactivate pre-existing faults and fractures, create new fractures and deform the rock matrix. An extreme example of the latter effect is seen in the Valhall and Ekofisk fields offshore Norway (Agarwal *et al.* 1997; Zoback & Zinke 2002; Barkved *et al.* 2003; Toublanc *et al.* 2005), where overpressured and undercompacted chalk underwent dramatic production-induced changes in porosity and, particularly, permeability. In such stress-sensitive reservoirs it can be difficult to distinguish matrix from fracture response. **Zhang *et al*.** describe a scenario in which they simulate the geomechanical response of a faulted and fractured reservoir to hydrocarbon production and water injection. Many fractured reservoirs are geomechanically insensitive (or at least sufficiently so that it can be treated as a second-order effect) or have a sufficiently homogeneous and reversible response that they can be adequately modelled by introducing pressure-sensitive permeability modifiers to the flow simulation model. Others are geomechanically sensitive and require a coupled simulation modelling approach (e.g. Koutsabeloulis & Hope 1998; Maillot *et al.* 1999; Settari & Walters 1999; Bagheri & Settari 2005).

Acute sensitivity to stress or fluid pressure perturbations which are small relative to the total stress state are a characteristic of critically stressed geological systems. In a reservoir context the critically stressed elements are typically faults that are on the verge of frictional slip or failure (e.g. **Zhang *et al*.**). In a broader context the same phenomenon is seen with earthquakes, where small stress perturbations can lock or release previously unstable or stable fault segments (Scholz 1990; Harris 1998). Critically stressed faults can be considered to buffer the subsurface stress state; stress cannot be increased substantially without activating some faults and relieving the stress increase. It is not necessary that every fault is critically stressed, only that the system as a whole is locally near failure. Near-critically stressed faults are likely to have slipped in the recent past in response to tectonic and other stress perturbations; as brittle faulting typically causes dilation, such faults may act as fluid conduits (e.g. Barton *et al.* 1995; Sanderson & Zhang 2004). That forms the basis for some fracture modelling approaches, where the proximity to failure of each mapped fault, and of smaller features such as subseismic faults or an idealized Andersonian joint set, is used as a proxy for fracture conductivity. Microseismic recording of production or hydraulic-fracturing induced earthquakes (e.g. Raleigh *et al.* 1976; Shapiro *et al.* 1997, 1999; Segall & Fitzgerald 1998; Rutledge *et al.* 1998, 2004; Maxwell *et al.* 2006) suggests that some reservoirs are at least close to being critically stressed, although interpretation may be complicated by poro-elastic effects and/or matrix compaction (e.g. Zoback & Zinke 2002). Where there is observational evidence for fault reactivation, the original proximity of the fault to failure can be inferred if the magnitude of the pore pressure perturbation is known (e.g. Raleigh *et al.* 1976). In other cases independently determined stress and fluid pressure conditions may lie close to the frictional failure envelope for favourably oriented reservoir faults. A critical state can be inferred from the stress-buffer argument, although care must be taken to avoid circularity where some of the input parameters were estimated by assuming a critically stressed state. The extent to which reservoirs in general or only certain faults are critically stressed is debated, although it is strongly indicated in cases where *in-situ* stress or fracture orientations change across them (e.g. Finkbeiner *et al.* 1997). Heffer *et al.* (1995) and Heffer (2002) have documented directionality in flow and pressure transmission during water injection in nominally unfractured reservoirs. The direction is consistent with the predicted strike of those faults which were closest to failure, implying that they were already hydraulically conductive or became so as a result of the fluid pressure increase caused by injection. The inclusion or exclusion of such effects in field simulations can have a significant impact on waterflood sweep efficiency; an unrecognized flow directionality will probably mean that most of the injectors are in the wrong place. Critically or near-critically stressed faults can also pose a drilling hazard. Mud losses may occur if the fault is reactivated by drilling mud pressure, which is typically hundreds or thousands of psi higher than formation pressure; and a fault that has previously been reactivated by injection may be associated with a swarm of open fractures which takes losses even if the drilling mud pressure is too low to cause renewed activation. Conversely, such a fault may be responsible for a formation fluid inflow or 'kick' if it communicates directly with an active water injector.

A bridge between the categorization of structurally complex reservoirs into faulted and fractured types is provided by **Main *et al*.** who document the geomechanical response of a conventional faulted reservoir to water injection. Fault behaviour (as barriers or pathways for enhanced flow) changed during field production but in a complex manner related to stress release or transfer along and between faults. It is likely that most of the permeability increases were due to small-scale fracturing, which locally enhanced fluid flow without necessarily forming a widely connected fracture network. In a sense they describe a fractured reservoir, but perhaps one that was not a fractured reservoir prior to water injection and which might never have displayed such behaviour if produced by primary depletion only.

Concluding remarks

The papers contained in this volume allow the identification of some priority future directions, where continued research and improved application, calibration and validation will add to the growing understanding and management of structurally complex reservoirs. These include:

1. The vital importance of generating robust 3D structural models as a platform for the detailed modelling of complex faulted or fractured reservoirs. Many reservoir studies suffer from the relatively poor quality of basic fault mapping, a shortcoming which is not compensated for by the application of progressively more sophisticated modelling techniques further along the workflow.
2. The importance of applying new methods for the inclusion of fault properties in reservoir models. These methods provide a means of performing geologically refined history matches, and an improved basis for defining fault properties and for production forecasting.
3. The need to develop effective upscaling workflows to ensure inclusion of subseismic structural complexity at the right level of detail in flow simulations. This requirement applies not only to the inclusion of subseismic faults and damage zones, but also to the preservation of features that may be below the resolution of a simulation grid (e.g. relays).
4. The requirement to progress beyond the notion of a single deterministic model, to incorporate the broad range of fault- and structure-related uncertainties. New methods can be used to incorporate uncertainties, but their widespread application may require a change in culture, together with the general acceptance that high quality geologically-refined production forecasting takes time!
5. The importance of improving the links between flow and mechanical feedback processes for the complex stress paths, reactivation of faults and other dynamic fracture damage experienced by reservoirs. Algorithmic improvements in geomechanical simulation (and reductions in computer costs) would extend the range of fields where coupled flow simulation modelling is routinely applied.
6. The introduction of geomechanical rigour into kinematic structural restoration and of kinematic constraints into geomechanical simulations would yield a coupled approach which simplifies both sets of constraints simultaneously with consequential benefits for flow prediction, particularly in fractured reservoirs.
7. Understanding the role of structure in reservoir and fluid behaviour on timescales much longer than production, will yield important insights, primarily in the context of CO_2 sequestration. There are lessons to be learned here from the contrasting behaviour of faults and fractures in conventional reservoirs, as observed when

comparing static (exploration) performance with dynamic (production) performance. Cross-learning is available from the mining, toxic and radioactive waste disposal industries, which have had to make similar judgements about the long-term behaviour of fault or stratigraphic seals and fractures.

8. The importance of improving our understanding and ability to model multiphase fluid flow behaviour in both fault-seal and fractured reservoir environments. This will require not just conceptual modelling and computational advance but also laboratory measurements at the limit of current technology and careful calibration against dynamic oil and gas field data. The introduction of a potentially miscible phase in the form of carbon dioxide introduces additional complexity to tertiary recovery and/or long-term sequestration plans.

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Full reference details for the papers presented in this book are provided in the prelim pages.

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