Carbonate rocks and petroleum reservoirs: a geological perspective from the industry

TREVOR P. BURCHETTE

Department of Earth Sciences, Royal Holloway University of London, Egham, Surrey, UK (e-mail: t.burchette@es.rhul.ac.uk)

Abstract: Carbonate oil reservoirs are sometimes regarded with apprehension in the petroleum industry since it can be difficult to predict the quality of, and ensure high recovery factors from, this rock family. Particular problems are the complex and heterogeneous nature of porosity in carbonate rocks, often leading to large ranges in permeability for any given porosity, and the organization of carbonate successions most commonly as vertically heterogeneous, but laterally persistent, layers.

Important issues that arise time and again in carbonate reservoir description include (a) predicting reservoir quality at inter-well scales and in uncored wells, (b) recognizing problematic high-permeability layers, (c) determining the permeability component to allocate to fractures and connected vug systems, and (d) populating reservoir models with representative physical parameters. Because porosity in carbonate rocks generally presents as diverse and heterogeneous, conventional core plugs are seldom representative of large rock volumes and significant issues remain in terms of the scale-compatibility of the various datasets for measured physical parameters that are used in carbonate reservoir description.

Many of the world's largest carbonate reservoirs were discovered and developed shortly after the Second World War and are now showing signs of maturity, expressed variously as poor pressure support, water or gas breakthrough and stranded resources. The proportion of the world's 'conventional' petroleum that is reservoired in carbonate rocks is commonly estimated at around 50–60% and many large carbonate reservoirs are likely to have a production lifetime beyond 50 years. It is no coincidence then that the petroleum industry has been the primary source of funding of and promotion of research into carbonate rocks and depositional systems, often with impacts extending well beyond oil and gas exploitation.

Our relationship with carbonate rocks has endured for thousands of years: fossils have captured the imagination, limestone caves and building stones have given shelter, marbles have adorned our public and living spaces and have preserved some of our most lasting physical images, and limestones and dolomites are utilized for numerous industrial processes ranging from road metal and cement manufacture to the production of steel. In addition, carbonate rocks host the largest proportion of the Earth's remaining 'conventional' petroleum resources and a good proportion of its essential base metals. Coincidentally, many of the world's premier vacation resorts are located in modern carbonate depositional environments.

Although familiar in many ways, certain physical aspects of carbonate rocks have remained enigmatic. For this reason, since the first commercial oil wells were drilled in the late nineteenth century, carbonate reservoirs have been regarded with some apprehension by the petroleum industry because it can be difficult to predict the reservoir quality of, and ensure high recovery factors from, this family of rocks. Not surprisingly then, the petroleum industry has been a fundamental influence in stimulating research on and developing our understanding of carbonate rocks and depositional environments, often with impacts that extend well beyond the exploitation of petroleum accumulations.

Those who work in industry often maintain that carbonate reservoirs are 'more difficult' than siliciclastic reservoirs, but this is a superficial contention; there are many equally difficult and complex siliciclastic reservoirs. Carbonate reservoirs, however, are very *different* from siliciclastic reservoirs and require an alternative knowledge base in order to effectively find, describe and interpret them. This brief review examines the manner in which studies of carbonate rocks and depositional environments have impacted the petroleum industry and how the petroleum industry in turn has impacted studies of carbonate rocks and depositional environments; it also offers a brief prospective on the directions that industry-related research, concerning in particular carbonate reservoirs, might take in the next few decades.

Retrospective

Any look forwards to where carbonate research may go (or perhaps *should* go) for the benefit of the

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petroleum industry in the next decades warrants a brief glance back at where we have come from over the last few.

Until the 1950s, carbonate research was a stratigraphic, substantially palaeontology orientated discipline and one for which James Hutton's concept that the 'present is the key to the past', while applied by researchers, was based on only limited familiarity with modern carbonate depositional environments. The post-war flourishing of research into carbonate sediments and rocks, recorded in reflective interludes in the early 1970s by discipline veterans such as Folk (1971), Bathurst (1975), Ginsburg (1974) and Wilson (1975), and more recently by Friedman (1998), was stimulated both by economic growth, with the consequent demand on the petroleum industry to supply supporting resources, and by renewed interest generally in the natural sciences.

The history of research into carbonate rocks since 1950, in common with other areas of geology, has been a story of continuous, incremental progress (observation . . . interpretation . . . application) rather than one punctuated by 'eureka' events as in certain physical or biochemical sciences.

While several large petroleum fields were discovered in the USA and Iran in the inter-war years using relatively simplistic exploration techniques, most of the larger oil and gas fields in the Middle East, and many in the USA and elsewhere, were discovered and put on production in the two or three decades after the Second World War (cf. Tiratsoo 1984). A disproportionate number of these fields contained carbonate reservoirs and certainly the largest accumulations discovered resided in carbonate rocks. Over the last 60 years, this has given the petroleum industry a strong imperative to better understand carbonate depositional environments, sediments and rocks.

Industry-funded and directed carbonate research in the 1950s and 1960s was initially strongly biased towards understanding modern carbonate depositional environments, facies and processes (Fig. 1) as companies sought to interpret and predict lateral variations in facies and reservoir quality in carbonate reservoirs, the largest of which have areas of several thousand square kilometres. Studies in Florida and the Bahamas, Belize and the Persian Gulf as wells as Pacific atolls and the Great Barrier Reef by,

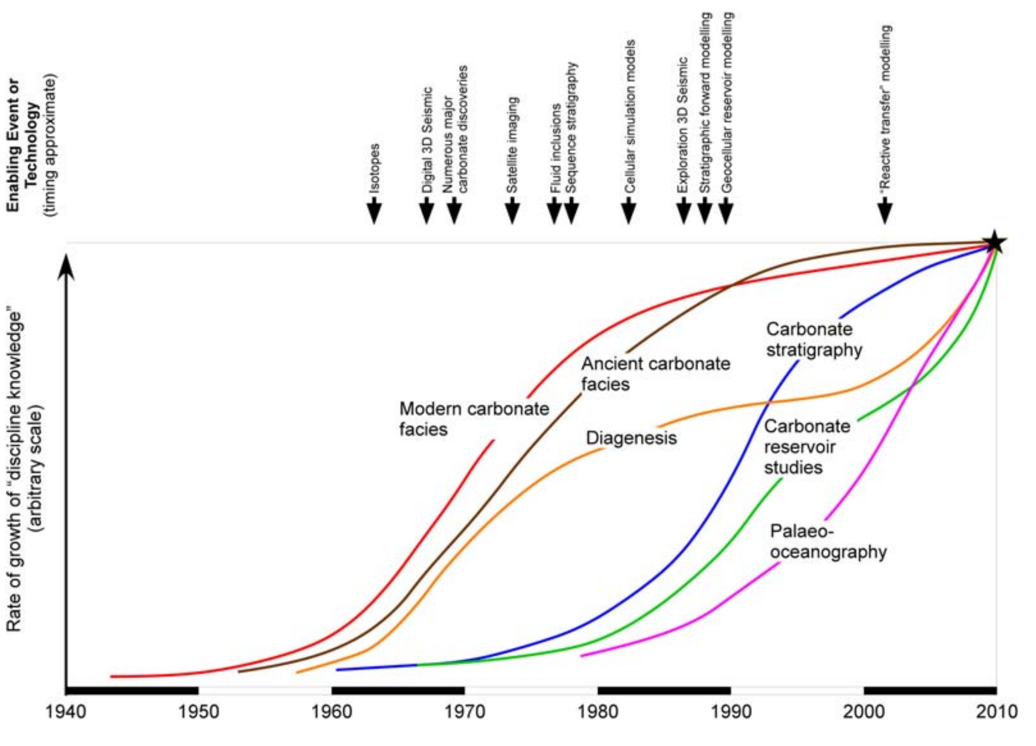

Fig. 1. Various subdisciplines within carbonate geology show different 'growth of discipline knowledge' curves (arbitrary *y*-axis scale); the point marked with a star represents our current state of knowledge. In the upper part of the figure some of the key 'enabling' events and discoveries are shown. Some subdisciplines, such as carbonate depositional facies are now on a 'plateau', while others are only now in vogue or becoming indispensible to carbonate reservoir exploration and exploitation.

amongst many others, Ball (1967), Bathurst (1967), Cloud (1962), Gebelein (1969), Davies (1970), Dunham (1967), Evans *et al.* (1969), Fairbridge (1950), Folk (1962, 1967), Ginsburg (1957, 1964), Illing (1954), Imbrie & Buchanan (1965), Kendall & Skipwith (1968), Kinsman (1964), Ladd (1950), Milliman (1967), Newell (1955), Newell & Rigby (1957), Purdy (1963*a*, *b*), Purser (1973), Shinn (1963) and Stoddart (1962) laid the foundation for the discipline of carbonate facies analysis. This work was consolidated in numerous papers, textbooks and syntheses on carbonate depositional systems and diagenesis in the following decade (e.g. Bathurst 1975; Wilson 1975; Sellwood 1978; Flügel 1982; Burchette & Britton 1985;) as well as special publications and memoirs from the SEPM (Society of Economic Palaeontologists and Mineralogists), American Association of Petroleum Geologists (AAPG) and IAS (International Association of Sedimentologists) far too numerous to detail separately here. During this time, much primary research was carried out internally within the oil companies that had large carbonate reservoir portfolios (Shell most prominent among these) to address gaps unfilled by contemporary university research. Significant studies of modern carbonate sediments in Florida and surrounding areas were also supported by the US Geological Survey, although not always with an industrial objective.

In the 1970s, much of the early expertise generated in the petroleum industry migrated into academia and during this episode the knowledge gained was imparted to the current 'mature' generation of carbonate researchers and industry specialists. This coincided in part with a renewed period of nationalization of oil assets and one or two revolutions, particularly in the Middle East, North Africa and elsewhere where carbonate reservoirs dominate. These events precipitated a change in focus for many of the international companies towards siliciclastic reservoirs in areas such as the North Sea in Europe and the North Slope in the USA. Due to easy oil production during the early lives of many of the largest carbonate reservoirs, the new national oil companies showed little interest in supporting fundamental research into carbonate reservoirs for the next 20 years. The discipline of 'carbonate sedimentology' became largely self-driving, albeit with some continued support and incentive from industry. The lessons and rules derived from studies of modern carbonates during this period became indispensible to the interpretation of ancient carbonate successions in outcrop and the subsurface (Fig. 1) and the available archive of case studies accumulated rapidly.

In carbonate reservoir systems, depositional facies and early diagenesis are not the only controls on reservoir quality, and alongside the studies of modern carbonates, burial diagenesis and stratigraphy became major focus areas, leading to what could be defined as an acme period in carbonate research in the 1970s and 1980s. During this time, the approach to carbonate reservoirs in industry also matured. The introduction of new tools, including digital 3D seismic acquisition and interpretation (Robertson 1989), sequence and seismic stratigraphy (see, e.g. articles in Loucks & Sarg 1993), improved borehole wireline log analysis, and various geochemical analytical techniques provided major advances in our understanding of the geometry, evolution of stratigraphic architectures and diagenesis of carbonate successions, and of the way in which depositional facies are integral within these frameworks. All of these aspects were developed by or for the petroleum industry to facilitate exploration and development.

Between *c.* 1990 and the present, the nature of oil industry involvement in carbonate research has undergone substantial changes. In today's environment of tighter corporate cost control, funding has often been ephemeral even in larger companies (various pers. comm.) and the emphasis within most companies is far less on 'pushing' primary research on carbonate rocks than on effectively applying the results from previous decades and collective 'pulling' of themed research into carbonates via relatively few university consortia. As always, there are a few notable exceptions to this trend where individual companies' interests are focused on major carbonate assets. In Europe, in particular, this reduction in industry input and restricted or redirected higher education funding, along with university geology department closures, has contributed to a decline in the number of students studying carbonate-related topics for higher degrees and in carbonate-related academic posts.

While there is undoubtedly still a significant amount to discover in modern carbonate environments that will impact our view of ancient limestones and dolomites (studies continue; see, e.g. Harris 2010), the pace has slowed and it can be argued that the petroleum industry has now accumulated a sufficient stock of 'two-dimensional' modern facies models and analogues to allow most carbonate exploration and reservoir facies interpretation problems to be addressed from first principles using the current body of knowledge. There are still limited areas for which our current analogue facies models are clearly inadequate, for example with respect to carbonate-dominated lacustrine facies, cool-water carbonates and carbonate source rocks.

As new tools have become available, the petroleum industry has adopted a more holistic approach to carbonate rocks so that attention is more appropriately focused on how reservoir facies are organized, often repetitiously, within three-dimensional stratigraphic architectures in response to various external controls. Insight has come, not just from modern environments, but through access to high-resolution 3D seismic data and outcrop studies (e.g. articles in Weimer & Davis 1996; Eberli *et al.* 2004). It would seem strange if a modern reservoir description study did not begin by generating a sequence stratigraphic framework from seismic, wireline logs and cores, some derivative of which generally forms the basis for layering in most static and dynamic reservoir models.

The relationship between carbonate sediments and antecedent structural topography and their gross variations with time and relative sea-level are well enough understood so that, in an exploration context, generating maps of gross depositional environments in which general facies distributions are conceptualized is no longer perceived as a major issue; access to data to do this in sufficient detail, however, remains a perennial problem. The routine application of sequence and seismic stratigraphic principles allows us to interpret the detailed evolution of carbonate platforms on seismic data and to populate these in new plays with meaningful depositional environments and conceptual reservoir potential. In contrast, predicting reservoir *quality* for carbonate plays and risking this element remains as large a problem as it ever was, particularly in little-explored basins. Discoveries in the South Atlantic of unexpectedly large pre-salt oil reservoirs in unusual lacustrine carbonates (e.g. Beltrão *et al.* 2009; Gomes *et al.* 2009) have shown just how limiting complacency in such matters can be.

In summary, the requirements of the petroleum industry have been the principal drivers of studies into the nature of carbonate rocks in the decades since the Second World War, and probably to a greater degree than for many other geological disciplines. A quick estimate suggests that over that period around 80% of books and papers on carbonate sedimentology have been published in industry-orientated vehicles (e.g. bulletins and special publications from the SEPM, AAPG, Canadian Society of Petroleum Geologists (CSPG), Society of Petroleum Engineers (SPE)/Society of Petrophysicists and Well Log Analysts (SPWLA) and other societies) or in journals and books from the large publishing houses that are commercially biased towards the industry. Many of the seminal carbonate research programmes, such as those on the Persian Gulf (Purser 1973), the Great Bahama Bank (Ginsburg 2001) and the Guadalupe Mountains (e.g. Kerans & Fitchen 1995), have also been supported by the petroleum industry. Over the last two decades, driven principally by concerns over climate change, studies of modern carbonate environments, in particular of tropical coral reefs, have once more flourished. These have taken on a new, ecological flavour not so directly connected with geology or the petroleum industry (see e.g. Glynn 1993; Goreau & Hayes 1994; Brown 1997; Kleypas *et al.* 1999; Goreau *et al.* 2000; Wilkinson & Souter 2008) and are being funded from different sources and published in a wider range of outlets. This new direction may conceivably provide feedback that changes some of our preconceptions about the growth of carbonate organisms and their relationship to oceanographic processes.

False perceptions?

A perception in many non-sedimentological disciplines, particularly in some corners of industry management, has long been that the range of petroleum reservoir types typically encountered looks something like this:

- deltaic/paralic;
- fluvial;
- deep water;
- shoreline and shallow marine;
- periglacial;
- lacustrine/playa;
- carbonate.

It is curious that a clear distinction has often been made between different kinds of siliciclastic depositional systems (even by non-geologists), but that many in the industry have failed to comprehend that carbonate depositional systems are equally diverse. This common misperception has been reinforced by the fact that many widely used general sedimentology textbooks, particularly those published in the 1970s and 1980s, have devoted just cursory comments or only one of many chapters to carbonate sediments (examine e.g. Reineck & Singh 1973; Pettijohn 1975; Reading 1978, 1996; Walker 1984) and that certain conference programmes, and indeed some university curricula, for many years perpetuated this imbalance. This may be because perception has been dominated by the almost entirely marine, largely organic origin of carbonate rocks or the superficially similar mineralogical and diagenetic issues ('limestones and dolomites') that characterize them. To the relief of many carbonate geologists, more recent general sedimentology textbooks do appear to be giving carbonate sediments greater prominence (e.g. James & Dalrymple 2010).

In a reservoir development context it is just as often the stratigraphic-scale controls on porosity and permeability distribution that are problematic since these determine reservoir layering, the distribution of problematic high-permeability zones, and the homogeneity of any secondary or tertiary oil displacement process. Each of the commonly recognized categories of carbonate depositional system, carbonate ramp, rimmed shelf and isolated build-up, has its own distinctive architecture and reservoir quality distribution. All also exhibit 'temporal' variation in facies character and distribution and eventually in reservoir properties that has resulted from organic evolution. This is not as immediately obvious to a 'layman' in the same way that a river or desert deposit is distinct from that of a deep marine fan. A typical range of carbonate reservoirs should, more realistically, include the following:

- mound/isolated buildup;
- shoal grainstone (ramp/rim);
- 'reef';
- neritic/shelfal;
- cyclic platform interior;
- pelagic/hemipelagic;
- dolomite/evaporite;
- karst-related;
- lacustrine;
- basinal mudstone/source rock.

Just as in siliciclastic environments, recognizing this diversity is not only a key aspect of reservoir description, but also of carbonate reservoir prediction in exploration settings. In the first case, this understanding allows the construction of realistic reservoir frameworks (e.g. whether horizontal or inclined correlation is appropriate) and controls the population of this with facies and rock types, and in the second it allows the locations, forms and extents of carbonate platforms to be predicted as well as some broad degree of reservoir character.

Intransigent carbonate reservoir issues and research drivers

Issues that are unique to carbonate reservoirs and have a significant impact on their development and commerciality, but that remain stubbornly difficult to deal with, are:

- permeability that can range over three or four orders of magnitude for a given porosity;
- complex, varied pore shapes, particularly in biogenic grains, with a high probability of multimodal pore-size distribution in any given sample (microporosity to vug);
- pore systems that frequently exhibit dual permeability (e.g. connected vugs) and 'low-resistivity pay' with poorly predictable lateral and vertical changes;
- physico-chemical properties that predispose to oil- or mixed-wetness and that make carbonate reservoir behaviour very sensitive to fluid properties;
- non-linear porosity/permeability relationships, except in uniform, fine-grained lithologies as in some cemented lime mudstones or chalks;
- non-unique log responses that make detailed reservoir 'rock type' prediction from logs problematic;
- discrimination between and determining the permeability component to allocate to fractures and touching-vug pore systems, particularly where the matrix itself already has dual-porosity/permeability characteristics;
- distinctive carbonate stratigraphic architectures that control the distribution of all of the above.

These distinctive carbonate reservoir characteristics and their implications have been discussed and reviewed by authors in various forms in numerous journal papers (most notably in AAPG and SPE publications) and textbooks over the past two decades (e.g. Roehl & Choquette 1985; Tucker & Wright 1990; Chilingarian *et al.* 1992, 1996; Lucia 1999; Moore 2001; Ahr 2008). All these aspects must be addressed when characterizing a carbonate reservoir, but the workflows and techniques that are used are in many cases still rudimentary. Effective solutions to these problems would carry huge economic impact in terms of additional recovery from mature carbonate reservoirs.

For fairly obvious reasons, there are many similarities between the architectures of siliciclastic depositional systems from similar environments through geological time; if this were not the case, our ability to interpret ancient siliciclastic depositional systems would look very different. While carbonate platforms also show broadly similar forms through geological time, the detailed internal facies characteristics between platforms of different ages can be markedly different. Prediction of this aspect in a petroleum geology context requires at times quite specialist stratigraphic knowledge. For this reason, at the scale of the carbonate 'geobody' dimensions and distribution that are important in carbonate petroleum reservoirs, the parameter data available for carbonate rocks are currently far fewer in comparison with the information that can be accessed for siliciclastic rocks. This disparity is due partly to a lack of appropriate research to date, but also to the diffuse way in which carbonate sediment is produced and redistributed and to later diagenetic overprint. It is consequently difficult at times to discern from subsurface data where one 'geobody' ends and the other begins, particularly in a horizontal dimension. Variations in the nature of warm-water, shallow-marine environments over geological time and of the nature of carbonate-producing organisms are also issues since, in contrast to siliciclastic systems, our modern transgressive, coral-dominated carbonate depositional systems are actually of restricted value as analogues for much of the geological record (e.g. Schlager & Ginsburg 1981; Wright 1994).

Some of the most intractable petroleum reservoir issues only become evident after decades of production, generally following the commencement of a secondary recovery process that introduces multiple fluid phases with contrasting mobilities into a reservoir. Instead of, at most, a decade or two of production, which was substantially the situation in the 1960s and 1970s when many foundational studies on modern carbonate settings were carried out, a good proportion of the world's larger carbonate reservoirs have now been produced for 40 or more years. Hosts of smaller reservoirs discovered in those years are close to depletion. Secondary recovery schemes are routine, and tertiary schemes commonplace in carbonate reservoirs (see e.g. Longnes *et al.* 1972), the latter often involving widespread hydrocarbon gas injection or combinations of hydrocarbon gas and water as, for example, WAG (Water Alternating Gas) or, increasingly, CO_2, nitrogen, surfactants and polymers (articles in Chilingar *et al.* 1972; Penney *et al.* 2005; Manrique *et al.* 2007).

In addition, huge volumes of heavy oil and bitumen are now known to be reservoired in carbonate rocks in various parts of the world (Briggs 1989; Buza 2008), the largest of which is probably the Devonian Grosmont Formation in Alberta (see e.g. Jiang *et al.* 2010), a resource that at up to 400 billion bbl in place is of a size that cannot be ignored. Whether such reservoirs can be produced 'cold' or 'hot' is highly dependent on the temperatures of the formations, the viscosities of the hydrocarbons and the carbonate reservoir qualities. New technologies and developments of older technologies such as steam injection are currently under wide investigation to access such resources (e.g. Edmunds *et al.* 2009; Jiang *et al.* 2010; Tang *et al.* 2011, 2012). Owing to their greater propensity to fracture compared with siliciclastic rocks, recovery of heavy oil from carbonate reservoirs by steam injection is both enhanced, due to efficient heat transfer to matrix blocks, and complicated as a result of potential early steam breakthrough.

The increasing maturity of many conventional carbonate reservoirs, with their current or emerging problems of poor sweep efficiency, water or gas breakthrough, lateral and vertical pressure differentials and inter-reservoir communication, is now creating the requirement for more sophisticated methods of modelling their architecture and dynamic behaviours at both the pore and stratigraphic scales. These issues are often related to reservoir heterogeneities and properties (e.g. wettability issues) that are unrecognized during initial depletion production. Taken as a whole, primary recovery factors from carbonate reservoirs commonly look disappointing, at around 10–20%, compared with sandstone reservoirs (e.g. Qing Sun & Sloan 2003; Xie *et al.* 2005 Manrique *et al.* 2007; Austad *et al.* 2008) and improved (optimized) or enhanced recovery techniques are frequently required in order to achieve acceptable recoveries. Huge progress has been made, both conceptually and in software applications, to facilitate the reservoir development process, not least in the manner in which uncertainty is managed throughout the development cycle. However, it remains abundantly clear that the single most important factor underpinning all reservoir modelling, management and mitigation activities, particularly in 'difficult' carbonate reservoirs, is a geological description and a static and dynamic data-gathering programme carried out in a timely fashion in the development cycle. This is the only route via which the information necessary to increase the representativeness of static geological (and thus ultimately simulation) models and understanding of field performance can be achieved.

New approaches to reservoir studies

Studies of carbonate sediments and rocks address the issues discussed above by contributing to the static characterization of the reservoir environment, but it requires strong interdisciplinary collaboration in order to make such work relevant to reservoir exploitation. The sedimentologist, for example, can classify the reservoir rocks or identify and place in a stratigraphic context apparent high-permeability 'thief' zones, but is unlikely to be able to predict in numerical terms how such layers or rocks might perform dynamically in a reservoir context. These aspects require accesses to a different, broad set of data and expertise and highlight the integrated approach that is required to understand all, not just carbonate, reservoir issues.

Reservoir description and simulation in data-poor environments is becoming increasingly an exercise in imagination on the part of the (carbonate) geologist. One new approach, for which the name 'top-down reservoir modelling' has been used (Williams *et al.* 2004), calls for the initial generation of numerous possible reservoir scenarios based on geological insight that are investigated using simplified simulation models. These models can be relatively quickly validated or eliminated to provide a manageable number of viable possibilities to investigate depending on the match that can be made to historical reservoir dynamic data (see also Oddvar *et al.* 1997; Onwunalu *et al.* 2008; Mohaghegh 2009). Techniques of this kind are widely applied in other disciplines such as climate, resource utilization and biosystems modelling where data are sparse, but uncertainty high. Model resolution is subsequently improved as new data are acquired. These methods allow forward planning for petroleum reservoir developments to be fast-tracked and uncertainties to be more comprehensively investigated than in conventional simulation and may be particularly well suited to coping with the many variables encountered in carbonate reservoirs. Disciplines that may input during the initial stages to this modelling approach include sedimentology, structural geology, stratigraphy, petrophysics, geophysics, petroleum geochemistry, petroleum engineering and reservoir engineering. Ultimately, of course, such an approach does not remove the requirement for geological understanding, reservoir description or reservoir monitoring. Detailed reservoir performance issues will always need to be explained in terms of physical processes related to *actual geology*. This is new territory for most geologists, who have traditionally approached reservoir description from a largely deterministic viewpoint, which can lead at times to an uneasy relationship between geologists and reservoir engineers.

Static geological models can be more complex by orders of magnitude than it is possible to model dynamically given current limitations of hardware and conventional reservoir simulation software (Aarnes *et al.* 2007). Upscaling of static detail to allow for runs on a convenient timescale is therefore unavoidable when using conventional simulators. Carbonate reservoirs are not special in this respect, but they often exhibit many scales of complexity, ranging from the pore systems, fine-scale stratigraphy, fractures and related relative permeability behaviour that are lost or homogenized during upscaling. Recent advances in multi-scale reservoir simulation, a finite-element mathematical approach that represents an alternative to the upscaling of detailed static geocellular models (Aarnes *et al.* 2005), is gaining in popularity for highly heterogeneous reservoir systems and so is also likely to find widespread application in carbonate reservoir modelling.

There is now a great wealth of physical carbonate reservoir material and dynamic information residing in industry archives and core stores that could, by applying appropriate interdisciplinary tools and concepts, be used to better understand the above issues and through this improve the tools available for carbonate reservoir management. While there is a growing body of literature on the stratigraphic frameworks for carbonate reservoirs and their impacts on simulation and reservoir management, much of this in SPE or related journals, much of the detailed reservoir information is never properly utilized, released or published, or is published in small snippets that have limited numerical analogue value. Data generated through corporate operational programmes (a) have actual substantial monetary value and (b) can be used to estimate reserves and both short and long-term production potentials of reservoirs, and so they also often have both business and political sensitivities.

A recent industry survey

In 2009/2010 a review of industry research requirements for carbonate reservoirs was held in London by the Industry Technology Facilitation organization for subscribing companies, among whose number are most of the major and medium-sized international oil companies. This involved a theme day or 'framing' session by representatives of these companies that outlined the major areas of industry concern (Table 1 represents unedited output from this process); then, over several sessions, a short list of research projects was selected that was considered to be compatible with those interests. From numerous items in the initial 'long list' the principle short-listed common interest areas were:

- carbonate reservoir rock typing;
- permeability prediction;
- the impact of microporosity on reservoir quality;
- the impact on reservoir performance of fractures and stylolites; and
- dolomites/dolomitization.

Conspicuously absent from this list are the themes of carbonate depositional facies and stratigraphy that were so prominent in research portfolios in the 1970s and 1980s and seismic aspects of carbonate rocks. Whether this simply reflects the collective experience of the representatives at the meetings or is confirmation of some more fundamental trend in the industry that makes these issues of less concern is difficult to discern. It should be noted in this context that many exploration interests are ephemeral, while many development-related interests are longer term. Somewhat surprising, however, was the fact that, of all the research projects put forward on these topics, only four were eventually funded by various companies on the themes of rock-type characterization, fractured reservoirs and dolomite formation ($\times 2$). While a good range of germane research projects was available, the restricting factor appeared from discussions to be limited funds and the multi-year commitment required for potential new programmes with no 'track record'.

Structural aspects of carbonate reservoirs

A characteristic, although not unique, feature of carbonate reservoirs is that fractures and stylolites are frequently perceived as playing a significant role in reservoir performance. For some of the reasons outlined below, both phenomena undoubtedly occur more commonly in carbonate reservoirs than they do in siliciclastic reservoirs. However, the dynamic impact of both in a carbonate reservoir context is commonly difficult to quantify. Moreover, as in all fractured reservoirs, where the well stock consists largely of vertical wells, dynamically important fractures and faults may not be sampled, increasing the uncertainty as to any fracture permeability component.

Table 1. *The unedited output from an Industry Technology Facilitation 'brainstorming' meeting in London in 2009 showing the five principle areas of concern with respect to carbonate reservoirs expressed by industry representatives, including those from several majors*

Rock typing	• Predict rock types and permeability in uncored wells • Better characterize the pore network and relationship between geological (facies/diagenesis) and petrophysical data • New reservoir rock typing workflows/approaches required • Effectively use old or low-quality data • Upscaling k_h/k_v – how to get from one rock type definition to reservoir models • Numerical models for permeability characterization of heterogeneous rock types
Permeability prediction	• Prediction of reservoir quality in inter-well areas • Understand processes of permeability improvement/reduction in carbonate rocks • How to determine best permeability values to assign to flow units in reservoir simulators? • How do diagenetic processes and properties relate to permeability distribution within carbonate stratigraphic architectures? • Require information on carbonate reservoir body geometries in three dimensions and how these relate to stratigraphy
Microporosity	• Role of microporosity in flow and production? • How to measure fluids in micropores and does the content change? • Understand relationship between micro and macro pore network • Require improved understanding of microporosity generation • Need to determine quantitative relationship between microporosity and SCAL data, that is P_c, K_r, etc.
Fractures	• Need to understand dynamic fracture behaviour in carbonates over time, • Distribution with respect to mechanical stratigraphy and rock types • Distribution of open fracture networks, microfractures and anisotropy • Fracture swarms at subseismic scale and fracture–matrix interactions • Understand the role of stylolites (particularly with respect to k_v or as conduits) • Recovery factors and production characteristics from fractured reservoirs
Dolomite	• Improve understanding of fault-linked and stratiform dolomite bodies, petrophysical properties and geometry in order to optimize field development • What is the lateral extent – how to constrain the dolomite 3D volume in reservoir models? • What are the dolomitizing fluid temperature characteristics? • What has been the impact on pre-dolomitization porosity distribution? • How does dolomitization relate to petroleum systems and hydrogeological control? • Need improved seismic detection of dolomite bodies

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The mechanical stratigraphies of carbonate successions can be markedly different from those of siliciclastic successions. Massive reefal or early-cemented platform margins have no counterparts in siliciclastic environments and in other settings interbedded lithologies create numerous permutations of mechanical layering ranging from thin-bedded limestones with shaly partings, to interbedded limestones and dolomites, or thicker beds of more poorly indurated pack- or grainstone with diffuse boundaries and varying degrees of cementation. These are distributed, often cyclically, within generally predictable stratigraphic frameworks of changing bed thicknesses and styles and can strongly influence fracture density and distribution and fault character (Wenneberg *et al.* 2006; Morris *et al.* 2009; Zahm *et al.* 2010). Shales that might facilitate bedding-parallel shear are abundant in siliciclastic successions, but are rare in carbonate successions, with the exception of environments that are transitional between muddy basin and slope or in mixed carbonate–siliciclastic successions. However, evaporite intercalations (mostly anhydrite) occur within some arid carbonate platform interior successions and may influence fracture distribution in a similar fashion.

In carbonate reservoirs the effects of fractures are commonly difficult to distinguish from the effects of thin high-permeability layers of touching-vug porosity or of conduits that originate through karst dissolution beneath major sequence boundaries. Where all of these features are present in a reservoir (and it is not uncommon for a genetic relationship to exist), this can produce an extremely heterogeneous system. Such reservoirs are among the most problematic of all to characterize, develop and manage regardless of matrix reservoir quality (see e.g. Jameson 1994; Popov *et al.* 2009), not least because it is difficult to isolate the dynamic impact of any single feature; if there is one area in which carbonate reservoirs can be said to be more 'difficult' than siliciclastic reservoirs, it is here. Characterization and exploitation strategies for such complex carbonate reservoirs are poorly developed and primary and secondary recovery factors for this kind still generally remain low (see e.g. Missman & Jameson 1991), in some cases at no more than 10%, due to variable reservoir quality and uncontrollable breakthrough of injection water or gas along conduits.

A widely held preconception is that indurated carbonate rocks *on the whole* fracture more readily than siliciclastic rocks owing to their greater brittleness (as a result of pervasive calcite cementation), although there is relatively little recent literature on this topic. Dolomites are often structurally more competent than limestones and, also being less soluble, seem to resist pressure solution (Glover 1969) so that, conceptually at least, they should tend to fracture more readily in the subsurface; however, this too is a little researched area (Hugman & Friedman 1979; Schmoker *et al.* 1985). The resistance of dolostones to chemical compaction also means that they may retain porosity (although not necessarily permeability) to greater burial depths than limestones do (Schmoker & Halley 1982; Halley & Schmoker 1983; Ehrenberg *et al.* 2006). On the whole, however, loss of porosity with depth is much more poorly quantified in carbonate rocks than it is in siliciclastic rocks, for which at least some predictive capability exists (e.g. Bloch 1991; Bjørkum *et al.* 1998).

Reservoir to reservoir faults in carbonate rocks are more likely to act as conduits than as seals since shale gouge is generally absent, while ancillary fractures are abundant. This leads to complex permeability evolution in the region around a fault as it develops (e.g. Billi *et al.* 2003; Micarelli *et al.* 2006), a characteristic that has implications in both reservoir development and exploration. In carbonate reservoir developments, faults typically act as vertical or lateral conduits or locally behave as only moderate lateral baffles where they are intensely cemented or juxtapose good reservoir against poor reservoir. Exploration for fault-sealed traps is less attractive in carbonate-dominated fairways for this reason unless clear juxtaposition of reservoir against a known seal can be identified on seismic.

In strong contrast to most siliciclastic slopes, carbonate platform margins of certain ages may be very steep and are commonly unstable during growth. They are prone to develop synsedimentary faults and fractures (e.g. Aby 1994; Kenter *et al.* 2005; Frost & Kerans 2010; Bertotti *et al.* 2011), which may be perpetuated into the subsurface as dynamically active features (Collins *et al.* 2006; Tankersley *et al.* 2010). In the deeper subsurface, where indurated margins overlie softer slope and basin sediments, compactional faults and fractures may also develop (Weber *et al.* 2008), both in the reservoir and above it. Open faults and fractures of all kinds may also strongly influence the location of karstic or burial dissolution or of subsequent diagenetic events such as dolomitization or petroleum migration.

Another significant issue that complicates the characterization and development of many carbonate reservoirs and can have considerable economic impact is that of vertical reservoir permeability. Shales and laminated siltstones that could act as strong vertical seals are absent from typical carbonate reservoir facies, although thicker intervals of evaporites can act variably as vertical seals. Limestones, in particular, are highly soluble and undergo chemical compaction (pressure solution) at relatively shallow burial depths (e.g. Bathurst 1975; Rutter 1983), often with concomitant zonal cementation (e.g. Heydari 2000). In contrast to many sandstone reservoirs, vertical v. horizontal permeability measurements from conventional core plugs in limestone reservoirs often exhibit a K_v/K_h ratio of around 1. However, such local measurements do not take into account the impact of successions of stacked stylolites or microstylolitic zones (e.g. as might be associated with a flooding event) that may substantially decrease the overall vertical permeability of a formation without forming a pressure barrier. Curiously, while such intervals are commonly encountered in carbonate reservoir developments, their dynamic impact appears to be little-researched and poorly documented. In some cases, the cementation zone around individual or grouped stylolites can be shown to form a substantial permeability barrier (cf. Johnson & Budd 1975; Koepnick 1987; Montaron *et al.* 2007) that only becomes apparent after a degree of reservoir depletion or when attempts are made to repressurize the reservoir through water injection.

Theme within a theme

Of all of the carbonate reservoir description issues discussed above, two particularly thorny problems have long hindered the efficacy of carbonate reservoir models. These are:

(a) the difficulties of predicting reservoir quality variations at inter-well scales; and

(b) the numerous issues around the way in which rock attributes can be represented in both static and dynamic reservoir models (more concisely: the 'rock-typing' problem).

Finding workable solutions to these aspects would signify a major advance in the characterization of carbonate reservoirs. For point (a), geological control can only be obtained by reference to appropriate modern *and ancient* analogues in which lateral facies variability can be viewed or imaged and mapped. Modern analogues, while providing insight, have only limited direct applicability to many ancient carbonate depositional systems. Conversely, analogue dimensional data from outcrop or the subsurface are valuable, but extremely diverse and seldom collected (or published) in readily useable form. The exceptions derive from just a few long-running research groups that have approached this aspect from first principles (e.g. Eberli & Ginsburg 1987; Kerans *et al.* 1994; Kerans & Fitchen 1995; Janson *et al.* 2007).

In point (b), geological control is principally derived from studies of depositional and diagenetic textures and other measured physical parameters. However, 'rock-typing' methods of this kind are of highly variable effectiveness as a vehicle for representing the dynamic behaviour of carbonate rocks within reservoir simulation models since they depend on the ability to discriminate clearly between dynamically important lithologies in cores and on wireline logs. This is something that is difficult to do for carbonate rocks using conventional datasets and methods, particularly in uncored wells. In this respect, too, there may be some conceptual hurdles to overcome.

Significant problems with a reservoir description often only become apparent when trying to extrapolate results to uncored wells using wireline logs, or later at the history-matching stage when revising a whole geological study becomes inconvenient, time-consuming and costly. A fundamental cause of such characterization issues derives from the scales at which geologists and petrophysicists make observations and try to reconcile their disparate sources of data, particularly if an iterative workflow has not been used. This impacts siliciclastic rocks too, but is particularly problematic in carbonate rocks because of their widely variable porosity classes, pore throat sizes and permeability distributions, and typically abrupt vertical facies changes (see e.g. Lucia 2008).

A classical and widely applied methodology for static carbonate rock-typing consists of petrographically identifying a 'reservoir rock type' using a thin section made from the end of a standard 1 inch core plug cut for routine porosity and permeability measurements (cf. e.g. Ruzyla 1986; Øren *et al.* 1998; Lønøy 2006; Hollis *et al.* 2010). Ideally the rock type will be a product of depositional texture and diagenesis that exhibits a particular dynamic character. This is then considered fairly blindly to be representative of the rock lithology and poro-perm characteristics for a volume around that point, often for a whole reservoir layer at the well location. A similar classification is made for other points where plugs have been taken, generally at a fixed spacing of 30–50 cm. Selected samples are also matched to generally sparser mercury-injection capillary pressure data and subsequently divided into permeability or pore- throat size classes to represent the (dynamic) rock types that will populate the static model. Other techniques are also widely used and range from the entirely petrophysical, for example Winland R_{35} (e.g. Gunter *et al.* 1997; Martin *et al.* 1997; Aguilera 2002) and various 'electrofacies' techniques (see Lee & Datta-Gupta 1999; Mathisen *et al.* 2003; Knecht *et al.* 2004), to combinations that utilize geological and petrophysical interpretation. Work carried out over the last 10–15 years by the Bureau of Economic Geology at the University of Texas, Austin, summarized comprehensively in Lucia (2008), has also addressed the spatial correlation of porosity and permeability in carbonate rocks, largely using outcrop data, and has highlighted in particular the poor horizontal v. the good vertical spatial correlation in permeability that generally characterizes carbonate formations (see also Jennings 2000). Consequently, while it is often valid to average horizontal permeability values within carbonate reservoir layers or geobodies, if data are abundant enough, this is less advisable over large reservoir thicknesses in layered carbonate systems since, in this dimension, stratigraphically controlled variations in permeability become very important.

A fundamental issue in the majority of carbonate reservoir rock-typing schemes is that the traditional basic data values derived from standard core poro-perm plugs are considered to be representative of too large a rock volume (see e.g. Gyllensten *et al.* 2004). Sampling bias can also be a major problem in carbonate cores and, for critical friable or very vuggy lithologies that cannot be sampled using conventional plugs, or may not even be recovered in core, measured porosity and permeability data may be missing entirely from reservoir datasets. Where core is not recovered, the geologist may not even realize that such lithologies exist in the well and, since they may have no particular distinguishing wireline log characters, their identification in uncored wells becomes moot. The incompleteness of datasets partly explains why there is often a significant mismatch in many carbonate reservoirs between permeabilities calculated from well test or production data and cumulative or averaged permeabilities from core plugs, and why a better match to actual reservoir permeability can often be obtained using whole core measurements (e.g. Ehrenberg 2007).

Friable, porous lithologies are also often the most permeable and their absence from a reservoir description is clearly undesirable. Small, plug-scale samples are demonstrably inadequate to represent the porosity and permeability characteristics of many coarser carbonate lithologies (Lønøy 2006). Work carried out to support the study of Dabbouk *et al.* (2002) demonstrated clearly that several petrographic rock types often exist in close juxtaposition within the volume of a 30 cm-long core sample (Fig. 2), particularly in vuggy or bioturbated lithologies, and that a single 1-inch core plug does not necessarily represent a core-scale sample either in terms of lithology or permeability. If the fundamental lithological characterization from thin sections is unrepresentative of the reservoir, then little else of the subsequent reservoir description can be valid.

Given the other uncertainties surrounding core recovery and sampling, plug-scale permeability measurement is thus often strongly subject to chance and a core plug permeability or pore-throat size distribution may not be clearly identifiable with a particular petrographic rock type. Similarly, mini-permeametry, acknowledging its unreliable aspects, often reveals an underlying marked heterogeneity in porosity and permeability that cannot be captured by single plug samples taken at typical 30 cm centres. Such heterogeneity can often be shown to be related to textural variations generated by bioturbation, sedimentary structures, the dissolution of large bioclasts and to the subsequent accentuation of all these features by diagenesis (Fig. 3).

In the context of the above discussion, it is also worth just briefly considering what proportion of a reservoir is actually sampled with cored wells and logs to provide rock data for a geological model. Development well spacing is determined by individual reservoir characteristics, but, to take one convenient example, in many Middle Eastern carbonate reservoirs, spacing in development patterns is currently at around 2 km. Since core is generally only taken in up to 10% of development wells, variations in reservoir quality between production

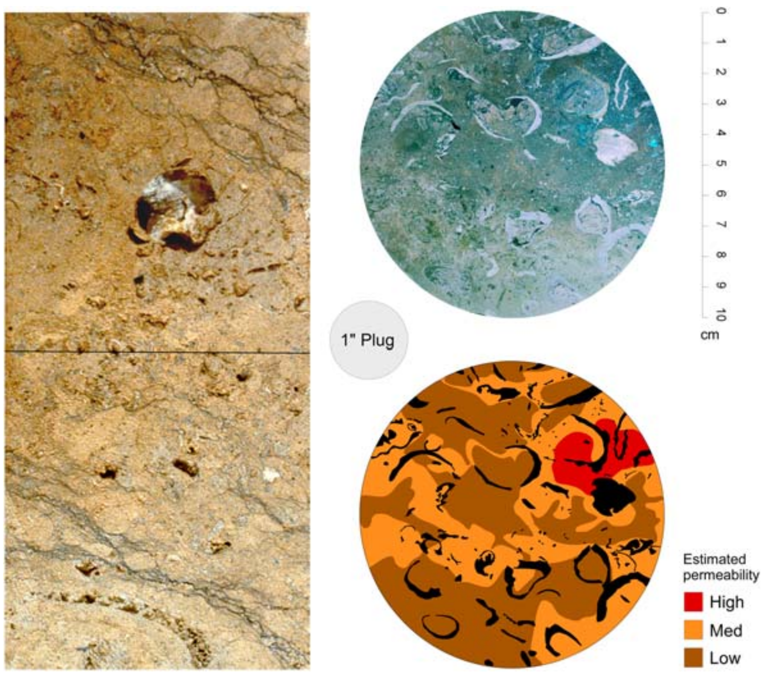

Fig. 2. A typical vuggy layer within a Kharaib (L. Cretaceous Thamama Group) reservoir from the UAE. Such layers, or intervals of stacked layers, in many cases representing parasequences are correlatable for large distances within many Kharaib reservoirs and can strongly influence sweep conformity due to their dual or triple permeability characteristics. Full-diameter thin sections made from core (line) show a wide range of petrographic 'rock types' and demonstrate that a single conventional core plug does not provide an adequate sample of a rock of this character since, depending on the location of the sample, it may include lithologies of markedly different permeabilities. Black areas in lower left figure represent impermeable rudist shell fragments.

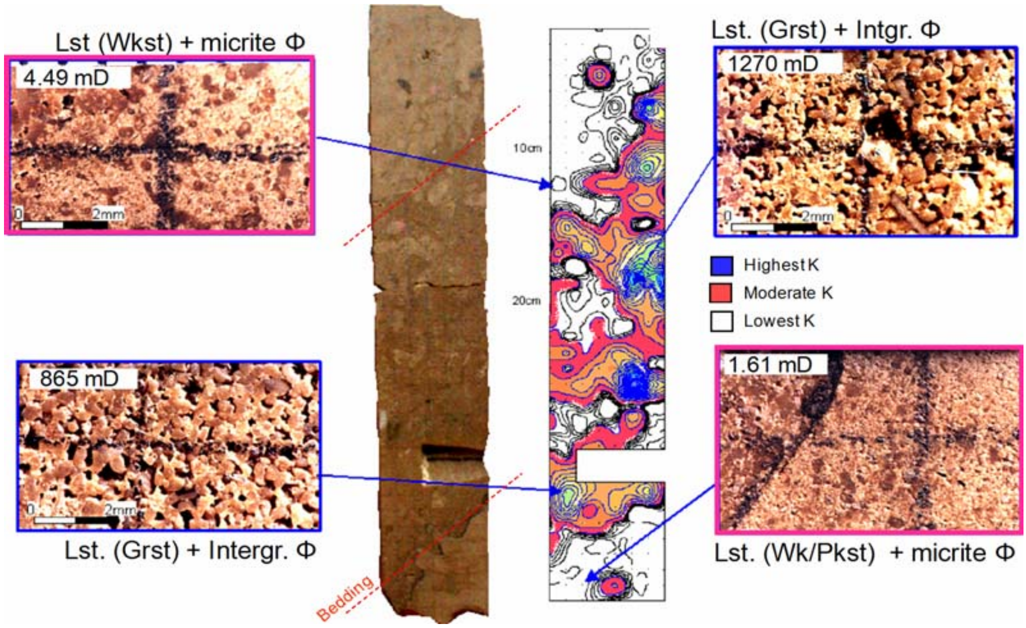

Fig. 3. Mini-permeameter map of a typical Kharaib (L. Cretaceous Thamama Group) bioturbated packstone/grainstone cored interval in an Abu Dhabi reservoir. This shows a wide range in rock quality within a small area that is controlled by stratigraphic layering and for which the single plug sample is unlikely to provide a representative permeability. Figure reproduced with kind permission of Nozomi Fujita of Japan Oil Development Company; slightly modified from the original.

or injection wells is often carried out by extrapolating reservoir rock-type and poroperm data from cored wells to uncored wells using wireline log suites. Most wireline logs sample a formation at a scale that is significantly coarser than can be achieved at the core scale, so the question of matching geological observations to wireline log response in carbonate rocks is often not at all simple. Even if all wells in a five-spot pattern at this spacing are cored for the entire thickness of a reservoir, the rock sample available on which to base predictions is miniscule as a proportion of the gross rock volume (Fig. 4) and geological knowledge, often guiding some statistical procedure, is required to extrapolate reservoir character between wells. Where, for example, only one well in such a scheme is cored, there is a strong requirement to develop a method for characterizing wireline log responses in terms of the geological parameters observed in the cored well to allow the uncored wells to be populated with reliable rock type data, thus providing additional data points that *have at least some geological control*.

There is, then, a significant problem concerning the scales at which data are collected and compared at a very early stage in reservoir description and, while this is probably common to all reservoirs, it is a particular issue with respect to carbonate reservoirs because of to the pervasive heterogeneity that they exhibit right down to the pore scale. Most carbonate rock-typing methods as currently practised include an inbuilt, uncontrolled upscaling process that often negates the careful data gathering that precedes it. This error is then compounded by poorly reconciling core-derived data with wireline log-derived parameters and dynamic reservoir data collected at yet larger scales.

Prospective

Looking forward to the next few decades at how research into carbonate rocks may impact the petroleum industry, it is important to distinguish between reservoir issues that can be addressed through improving our knowledge of the geology of carbonate rocks *sensu stricto* and those that represent reservoir problems that can be overcome through the application of generic tools and technologies that allow better physical resolution or imaging, essentially in a fashion that is little different to that applied to all other reservoirs (Table 2).

In the latter context, we can point to the improvements in computational technologies and the reservoir modelling and simulation methods discussed

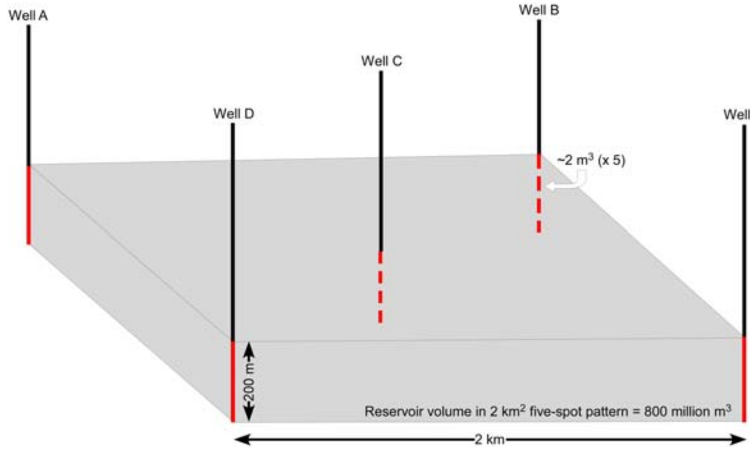

Fig. 4. The problem is not what you see, it is what you do not see... the gross rock volume in (for example) a typical Middle Eastern five-spot pattern development with a 2 km well spacing and a 200 m-thick reservoir interval is around 800 million m^3. The volume of reservoir rock recovered in a typical cored well through the same reservoir with a 10 cm core is around 2 m^3, if recovery is complete. Even if all wells are cored with 100% recovery (not often the case), we are extrapolating properties from a sampled 10 m^3 to 800 million m^3 gross volume, that is with reference to just 0.00000125% of the gross rock volume (and a good deal of geological intuition). Wireline logs will sample a somewhat greater volume at more limited resolution.

above, or to emerging smart-well technologies and chemical water shut-off mechanisms that mitigate the dynamic impacts of heterogeneities typical of carbonate reservoirs. Many carbonate reservoirs contain significant zones of poor quality pay or have thick transition zones with low hydrocarbon saturations; technologies that facilitate the depletion of such intervals will be in significant demand, perhaps learning from innovations driven by developments in the area of unconventional reservoirs.

Being able to image the reservoir or injection water flood-fronts in adequate detail is clearly one way of addressing the key problem of inter-well heterogeneity. While difficulties remain in using, for example, 4D seismic to monitor flood fronts in many indurated carbonate reservoirs (e.g. Lumley 2004), attempts are increasingly being made to use this technique (particularly in relation to hydrocarbon gas or CO_2 injection), as well as time-lapse Vertical Seismic Profiles (VSPs) and cross-well seismic tomography, towards this end (Harris *et al.* 1995; Tucker *et al.* 1998; Li 2003; Soroka *et al.* 2010). Improvements in seismic resolution and attribute analysis (stratigraphy, porosity, fractures, etc.) are clear goals for the geophysical community with an ultimate (but possibly unrealistic), prize of *in situ* measurement of reservoir porosity and permeability and real-time imaging of flood fronts.

Other generic technologies that are becoming commonplace (Table 2) enable us not only to investigate carbonate reservoirs more thoroughly, but also to learn more generally about carbonate rocks – for example, the detailed seismic-stratigraphic and structural interpretation that is possible on many modern high-quality 3D seismic datasets, the application of X-Ray Computed Tomography (X-Ray CT)-scanning, Nuclear Magnetic Resonance (NMR) and borehole image logs to mapping pore geometries and porosity (and potentially permeability) distribution at several scales, and new ways of using geochemical techniques and forward modelling to understand carbonate diagenesis. In order to correctly interpret the products of all of these technologies in a carbonate reservoir context, however, fundamental knowledge about the nature of carbonate rocks, their mineralogy and depositional origin is still essential.

One of the areas in which significant advances are promised is in the representation of the complex pore characteristics of carbonate rocks in reservoir models. To this end, a number of research groups are looking at methods of more representatively modelling carbonate pore geometries and distributions and relative permeability behaviour using mathematical models and proxies from image logs and X-ray CT data (e.g. Dabbouk *et al.* 2002; Aarnes *et al.* 2007; Tuanfeng *et al.* 2009). The application of multi-scale reservoir simulation and other emerging innovative approaches to reservoir simulation have been mentioned in this connection.

There can be little doubt that the accuracy and efficacy of static and dynamic carbonate reservoir models will continue to increase over the next few decades, and probably at a faster rate than hitherto, as learning from mature fields becomes accessible

Table 2. *Carbonate specific geological issues in reservoir exploration and development v. other generic aspects and technologies that contribute to the activity of carbonate reservoir exploitation. Any of these columns could be regarded as a list of areas in which further research would have an economic impact on carbonate reservoir exploitation, but the final column attempts to highlight some possible future research foci that would hold particular potential*

Activity	Carbonate-specific geological issues	Generic aspects	Enabling technologies	Impacting future research focus
Exploration environment	• Predictive palaeo- oceanography • Seismic stratigraphic interpretation • Carbonate source rock distribution/identification (seismic) rock properties • Porosity/permeability v. depth • Regional diagenesis • Carbonates v. structure • Sealing in carbonate systems • Fault sealing	• Attributes from seismic • Fracture distribution from seismic • Basin formation and subsidence history • Petroleum systems modelling • Exploration history • Use of analogues • Access to new data • Integration of datasets from multiple disciplines	• Increased seismic resolution • Exploration 3D • Seismic processing • 4C seismic • Non-seismic chemical and geophysical methods • Fluids from seismic • Satellite photogeology • Exploration process	• Seismic acquisition and processing • Plate tectonic evolution • Large-scale structural geology • Field and prospect analogue databases • Integrated regional geology • Integration of petroleum systems and diagenetic forward modelling
Development environment	• Stratigraphy and cyclicity • ‘Geobody’ dimensions and geometries • Carbonate k_h/k_v • Poroperm distribution • Diagenesis and karst • ‘Reservoir rock-typing’ methods • Carbonate pore geometry and connectivity • Wettability in carbonate systems • Reservoir properties in uncored wells • Appropriate scaling of core measurements	• SCAL measurement • Kr modelling • Stimulation techniques • Log interpretation • Application of analogues • Static modelling techniques • Dynamic modelling techniques • Upscaling techniques • Fault and fracture analysis • Attributes from seismic • Integration of datasets from multiple disciplines	• Water shut-off • Water chemistry modification • Water/gas handling • Horizontal wells • Smart wells • SCAL analysis • Static/dynamic modelling software • Wireline logging tools/ interpretation • Processing speed • Seismic resolution • Seismic processing • 4D seismic • Seismic attributes	• Outcrop analogue studies • Statistical representation of carbonate pore systems/ fluid flow • Scaling issues in carbonate reservoir characterization • Fault and fracture characterization • Permeability from wireline logs • Attributes from seismic

and as new techniques and technologies with which to analyse reservoir rocks become commonplace in the industry. Much will depend on the computer software and hardware advances that will undoubtedly occur (see e.g. Denning & Metcalfe 1997), possibly in ways that we cannot currently foresee. Simple evidence of this is the new ease of constructing and visualizing digital models in a manner that was either impossible or would have taken an age even 20 years ago. Eventually being able to construct and initialize full-field simulation models at static-model resolution, despite what appears to be currently prohibitive complexity, might go some way towards addressing the peculiar architectural issues that impact the characterization and management of some carbonate reservoirs. Some of the new ways in which uncertainty may be accommodated in reservoir models have been discussed above.

Similarly, the advent of such intuitive tools as Google Earth for visualization of outcrops and modern depositional environments could hardly have been envisaged 20 years ago, (a) because the full potential of the internet had not been realized, (b) because the software had not been devised, and (c) because the photographic material that has made it possible did not exist or was not freely available. Today, there is hardly a fieldwork or drilling campaign that does not begin with a satellite image and digital elevation survey using this or similar freely available tools.

Major advances are being made towards better understanding carbonate diagenesis (many aspects of which, such as dolomitization, have remained enigmatic for decades) within stratigraphic and structural frameworks. Semi-quantitative digital forward models that can account more holistically for the fluid and chemical fluxes responsible for various carbonate diagenetic processes such as dissolution, cementation, compaction and dolomitization are under development in various organizations. Such forward 'reactive transfer' modelling (Whitaker *et al.* 2004; Jones & Xiao 2005, 2006; Paterson *et al.* 2006, 2008) may provide greater insight into the ways in which carbonate rocks transform during burial, although whether more than a broadly qualitative *predictive* capability can ever be achieved remains unclear. Combination of such systems with petroleum systems modelling may provide one route towards a better understanding of carbonate diagenesis on a regional scale (e.g. Hantschel & Kauerlauf 2009).

Promising research into the geometries, dimensions and stratigraphic contexts of depositional bodies (such as mounds, shoals and channels) and their partitioning with sequence stratigraphic frameworks in both modern and ancient carbonate depositional systems is being carried out within a small number of companies and by industry-funded research groups such as the Bureau of Economic Geology Reservoir Characterization Research Laboratory and the University of Miami. These are essential components for spatially populating carbonate static reservoir models with attributes. Data from such studies also form useful training input for applications that use multiple-point statistics for such purposes (see, e.g. Harding *et al.* 2005; articles in Grammer *et al.* 2004), although modern carbonate systems are limited in diversity and distribution and subsurface examples have relatively specific relevance.

The cumulative body of literature that is now available from outcrop and developed reservoirs, but was absent 30 or 40 years ago, is allowing more sophisticated application of analogue data to carbonate reservoir characterization and has stimulated the development of various subscription databases synthesized from published data sources. It seems likely that these will continue to grow, as material is published, although such sources will always be dependent on what is released by the owners of data. There is, however, also an increasing, slightly unhealthy parallel trend for many companies to rely on these common sets of processed open-source data in lieu of their own in-house research. This holds the inevitable danger that companies may eventually regard arising opportunities from similar viewpoints rather than working from first principles.

Final comments

Finally, it is of interest to observe that over the last 30 years the petroleum industry has through necessity embraced one of the greatest revolutions to ever impact society and the sciences, namely the introduction of efficient, intuitive computers. Over the careers of the current 'retiring generation', the industry has progressed literally from slide rules or hand calculators and pens and paper towards near total reliance on ubiquitous computing, whether for authoring, contacting, mapping, drafting, calculation, analysis, visualization or simulation; many of that group will remember the day when the first computer or mainframe terminal appeared on their desk. Over the same period, 'geoscience' in the petroleum industry has progressed from discrete functional units of disciplines that largely supplied expertise on a service basis to become more or less synonymous with multi-disciplinary integration and collaboration, often with the application of specialist software and digital reservoir modelling, whether in structural geology, petrophysics, geochemistry, stratigraphy or (carbonate) sedimentology.

The efficacy of this revolution is undeniable. It has permitted fundamental progress in the way in which data are collected, collated, visualized and interpreted and in the manner and speed in which the physical aspects of petroleum reservoirs are analysed; progress is likely to accelerate and many of the laborious procedures that we now use will undoubtedly be automated, single-button activities in the future. The possible emergence of true artificial intelligence over the next 20–30 years (Kurzweil 2005) leads to the sobering and uncomfortable speculation that many of the complex reservoir development activities that highly trained geologists and engineers pull their hair out over now might within the 30- to 40-year careers of younger petroleum industry employees be performed by intelligent machines (e.g. Ford 2009). Nevertheless, the current seductive ease with which data can be manipulated, interpreted and displayed, and consequently also gross errors made, means that it is absolutely imperative that expert geological oversight be preserved at all stages of reservoir characterization. For many of the reasons outlined above, this trend is particularly important with respect to carbonate reservoirs. We should remember that a digital geological representation is only as good as the data and interpretation that it comprises; the old adage 'rubbish in, rubbish out' is entirely appropriate in this context and the industry continues to require highly experienced carbonate sedimentologists. Only the supply of such individuals in sufficient numbers is possibly in doubt.

Over the last decade, causatively perhaps, there has been an alarming reduction in the familiarity shown by many younger geoscientists with rocks, particularly carbonates, whether in the field or in core. Classical disciplines normally studied to PhD level and upon which the industry heavily depends, such as sedimentology, petrography and stratigraphy, are in decline due to university department closures and reductions in public and industry funding. While courses at MSc level are still moderately popular, graduates with these degrees do not often aspire to become industry carbonate specialists. This has created something of a dilemma for university departments that have had to adapt to this new demand. Traditional field- and laboratory-based PhD studies are surely the best way to underpin specialist understanding of carbonate rocks, but industry requirements are increasingly for geologists who have not only this experience, but also extensive software skills that allow them to contribute immediately in a digitally productive fashion.

There has also been a parallel trend in some large companies, now to some extent in reverse, to divest more fundamental specialist activities such as core logging, petrography and correlation to external consultancies, leaving the company geologist once removed from the reservoir rocks. The geologists who are best able to provide knowledgeable input to the exploration for, and characterization of, carbonate reservoirs, are those who develop a first-hand, in-depth understanding of the rocks, and this can be achieved in only one way – by taking every opportunity to experience them, in core, in thin-section and in the field. In some respects, for the practising carbonate geologist, the workstation has become something to escape from as often as possible. In response, many larger companies have developed compulsory further training programmes that run for several years after graduates join and that are designed to normalize competencies across the company, but which are often relatively weak on exposure to rocks.

The proportion of the world's *conventional* petroleum that is reservoired in carbonate rocks is commonly estimated at around 60%. Giant carbonate reservoirs account for a disproportionate share of this volume (see e.g. Unpublished Schlumberger Market Analysis 2007); this is unlikely to change substantially and many of these reservoirs are 'super-giants' that will have long production lifetimes. In the 'end-game', or at least the final third, of the pervasive global petroleum economy, in which we may already find ourselves (Deffeyes 2001; Roberts 2004; Greene & Hopson 2006; Mohr & Evans 2008; Bardi 2009; De Almeida & Silva 2011), enhancing oil and gas recovery from carbonate reservoirs will become disproportionately important. Many of the world's super-giant reservoirs and the greatest proportion of the world's proved conventional reserves reside in the Middle East (BP Statistical Review of World Energy, 2008; Montaron 2008), a region in which carbonate reservoirs predominate. Many of these reservoirs show forward production profiles that extend for 40–50 years and, for a few, for up to a century. Unconventional petroleum reserves are subject to much uncertainty and long production lead times and may not be able to compensate quickly enough to impact the decline in production from conventional sources (Bentley 2001; De Castro, *et al.* 2009).

Conclusions

The petroleum industry has been the principle impetus behind research into carbonate depositional environments, sediments and rocks for the last half-century, during which time discipline knowledge has seen steady incremental growth. This involvement has, of course, not been entirely altruistic since the principal motivation was a requirement to better understand carbonate petroleum reservoirs for economic reasons. With similar motivation, the industry has also developed or promoted new analytical tools, such as sequence and seismic stratigraphy and biostratigraphy, as well as many more generic measuring tools, the applications of which have further enhanced our understanding of carbonate depositional systems.

Particular carbonate-reservoir issues that impact the petroleum industry fall into several categories: stratigraphic, diagenetic and rock-fabric issues. These affect developments costs and recovery factors and therefore have significant economic impact for both companies and countries. While significant progress has been made on the stratigraphic aspects of carbonate reservoir description and prediction, major hurdles still exist with respect to understanding and dealing with the uncertainties that derive from the many styles of carbonate reservoir heterogeneity. New generic technologies and workflows based on digital modelling are emerging that may allow progression towards a solution to this problem, probably over the next decade. However, we cannot simply rely on technology; this is just an enabler – the whole process has to be supported by geological understanding.

I am grateful to the organizers for the opportunity to present the keynote on which this paper is based at the Geological Society meeting on Advances in Carbonate Exploration and Reservoir Analysis, 3–5 November 2010 and to industry colleagues for their insight on these topics over many years. I thank S. Agar and A. Horbury for their detailed and helpful reviews of the original manuscript. I am grateful too to N. Fujita of Japan Oil Development Company for permission to include Figure 3. All opinions expressed here are my own.

In a recent discussion with P. Wright, we considered what had triggered our interest in science and in particular geology. His immediate response to the question was that it was a book called *The World We Live In* (Life and Lincoln Barnett 1956), published in the UK by Collins. This so completely matched my own experience that we felt that, while maybe just an odd coincidence, it might actually not be that rare. We wondered also at that point how many other scientists and geologists of our generation were stimulated to follow their careers by owning a copy of this, to a child in the 1950s, wonderful book. Here are my rather belated thanks to the authors and publishers of that book for their unmeasured, but conceivably substantial, contribution to the progress of the natural sciences.

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